DRAFT/PROPOSED

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **April 14, 2025**

TO: Phillip Fielder, P.E., Chief Engineer

THROUGH: Richard Groshong, Environmental Programs Manager
Compliance, Enforcement, and Surveillance Sections

THROUGH: Eric L. Milligan, P.E., Engineering Manager, Engineering Section

THROUGH: Alex Johnson, E.I., New Source Permits Section

FROM: Joseph K. Wills, P.E., Engineering Section

SUBJECT: Evaluation of Permit Application No. **2012-704-C (M-17) PSD**
Phillips 66 Company
Ponca City Refinery
Facility ID No. 314
Latitude 36.68807°N, Longitude 97.08786°W
Sections 33 & 34, Township 26N, Range 2E
Sections 3 & 4, Township 25N, Range 2E
1000 South Pine, Ponca City, Kay County, Oklahoma

SECTION I. INTRODUCTION

Phillips 66 Company (Phillips 66) has applied for a PSD major source construction permit for a significant modification for their Ponca City Refinery facility (NAICS 324110 / SIC 2911). The Ponca City Refinery is currently operating under Title V Permit No. 2012-704-TVR (M-16), issued on January 23, 2025, along with several active construction permits. The Ponca City Refinery is an existing Prevention of Significant Deterioration (PSD) major stationary source and a major source of HAP emissions.

Phillips 66 Pipeline Company owns and operates three adjacent facilities that support the transportation of non-processed petroleum into and finished products out of the Ponca City Refinery. These "Pipeline Activities" consist of the Ponca City South Tank Farm, the Ponca City Products Terminal, and the Cherokee Pump Station. These facilities are considered collocated and part of a single facility site for the purpose of emissions evaluation and regulatory applicability (see Section III); however, they are operated under a separate Part 70 permit, Permit No. 2018-1651-TVR2, issued on August 21, 2020. The Ponca City Refinery is also considered collocated with the Jupiter Sulfur, LLC sulfur/nitrogen fertilizer production facility, which is adjacent to the Ponca City Refinery. Jupiter Sulfur is operated under a separate Part 70 permit, Permit No. 2022-0436-TV (M-1), issued on January 15, 2025. Future permitting and modifications of the Ponca City Refinery and associated permits need to be based on the combined emissions from both the

Ponca City Refinery, the Pipeline Activities, and Jupiter Sulfur and need to be considered prior to making a determination for each permitting action. Applicability of Part 70 requirements or New Source Review (NSR) requirements should also be based on the combined emissions of the Ponca City Refinery and the Pipeline Activities.

Total facility site emissions, excluding trivial and insignificant activities, are shown in the following table.

Activity	**NO_X**	**CO**	**SO_2**	**VOC**	**PM_{10}**
	TPY	**TPY**	**TPY**	**TPY**	**TPY**
Refinery	1,516	1,493	925	4,289	618
Pipeline Activities [(1)]	2	5	-	214	-
Jupiter Sulfur [(2)]	97	11	96	-	16
Totals	**1,615**	**1,509**	**1,021**	**4,503**	**634**

(1) Data extracted from Permit No. 2018-1651-TVR2, issued August 21, 2020.
(2) Data extracted from Permit No. 2022-0436-TV (M-1), issued January 15, 2025.

SECTION II. REQUESTED CHANGES

The Ponca City Refinery is submitting this application to modify the several projects authorized under Permit No. 2012-704-C (M-11), issued on October 13, 2023.

One of the 2020-2022 Long-Range Plan (LRP) projects was the replacement of the waste heat boiler (B-5004) associated with the No. 5 FCCU with a shell-and-tube waste heat exchanger. The Ponca City Refinery expected this project to result in decreases of all emissions since it would involve a reduction in fuel combustion. However, testing and CEMS data for the No. 5 FCCU following the project revealed elevated CO emissions. As a result, the annual-average CO emission limit of 46.1 TPY under Specific Condition No. 1 for emissions unit group EUG FCC-1 should be increased to 206.7 TPY. No change is necessary for the existing emission limit of 150 ppmvd at 0% oxygen, on a 365-day average) in the same permit condition. The 206.7 TPY value corresponds to the 150-ppmvd at 0% oxygen permit limit. Phillips 66 has requested that the pound per hour limit in the specific conditions be updated to correspond to the 206.7 TPY, which is estimated to be 47.2 lb/hr CO. Carbon dioxide (CO_2) emissions from the No. 5 FCCU are also higher than expected. No permit limit changes are necessary for any other pollutants. As a result of the CO emissions increase following the replacement of the No. 5 FCCU waste heat boiler (B-5004) with a shell-and-tube waste heat exchanger, the No. 5 FCCU is subject to NSPS, 40 CFR Part 60, Subpart Ja, for emissions of CO. The No. 5 FCCU will remain subject to NSPS, 40 CFR Part 60, Subpart J, for all other NSPS covered pollutants emitted by the No. 5 FCCU (i.e., PM, and SO_2).

Additionally, Phillips 66 outlined several cancelations and scope changes for other ongoing 2020-2022 LRP-related planned work in their application:

- Canceled Projects:
  - Saturated Gas Plant Compressor Replacement;
    - Engines E-0068 and E-0072 will not be removed and will remain in service.

  - Tank T-0114 Replacement;
  - Tank T-0163 Replacement;
  - Maximum Capacity Utilization (MaxCap) Project; and
  - HF Alkylation Unit Expansion – Depropanizer Tower Reboiler Reliability.
- Modified Projects:
  - Due to the cancelation of the HF Alkylation Unit Expansion – Depropanizer Tower Reboiler Reliability project, debutanizer reboiler H-0060 is not expected to see any increase in annual fired duty or emissions limit increases. As a result, the H-0060 is no longer considered an associated emission source to the project.
  - No. 4 FCCU Yields Improvement and Reliability Project has been modified to include the installation of a chiller for the main air blower inlet and a change in the future projected unit feed rate from 30,000 barrels per day (BPD) to 27,000 BPD.

Lastly, in addition to these 2020-2022 LRP-related changes, Phillips 66 is requesting the following changes to the permit specific conditions and/or permit memorandum:

- Change the factor used to estimate the future actual NO_X emissions for heater H-0004 from 0.150 lb to 0.127 lb/MMBtu (0.110 lb/MMBtu plus a 1.15 safety factor) based on recent stack testing;
- Change the fugitive components VOC emissions related to the No. 5 FCCU due to the addition of three relief valves; and
- Add two 16-inch isolation valves and two 4-inch isolation valves at the No. 2 CTU. These valves will be placed between the preheat train and the preflash tower, allowing for parallel clearing of this equipment and overall more expeditious decoking of the No. 2 CTU. Decoking occurs every other year, and this project could result in an extra 12 hours of operation during those years. The project potentially allows for an extra 30 BPD at the No. 2 CTU.

Due to the changes in the No. 5 FCCU CO and CO_2 emissions, the PSD applicability analysis completed for the 2020-2022 LRP Project has been revised. The PSD review now concludes that this project is considered a major PSD modification for CO and CO_2. As such, BACT and ambient air impacts analyses were required.

SECTION III. APPLICABILITY OF OTHER FACILITIES ADJACENT TO THE PONCA CITY REFINERY

The Ponca City Refinery complex and adjacent areas contain other facilities with activities that may or may not be related to the operation of the Ponca City Refinery. The applicant supplied an analysis of these facilities to determine if any need to be included in the site emissions for this permit. AQD has reviewed and agrees with the following analyses.

III.1 Refinery Complex

Some buildings, groundskeeping, and utility operations are located on company-owned property, but outside of the refining process unit fenceline. This includes non-process boilers, emergency generators, fuel storage tanks, and non-contact cooling towers. Steam produced in the refinery is

used for heating buildings. Fuel storage tanks are used for grounds keeping and building complex maintenance activities. Cooling towers are used to provide cooling for buildings and for non-process boiler feed water. Since these activities support or are supported by the refinery, they are considered to be associated with the operation of the Ponca City Refinery and are included in the refinery's Title V permit.

III.2 LiquidPower Specialty Products Inc. (LSPI)

SIC Code 8731 - Commercial, Physical and Biological Research (Major Group 87: Engineering, Accounting, Research, Management, and Related Services). The refinery leases laboratory space to LSPI, which is an independent business that develops and delivers pipeline flow improver solutions for crude, refined products, and non-potable water pipeline operations. The laboratory space is physically located in the former company research and development building which is outside of the refining process unit fenceline. Because the building is located on refinery-owned property, process wastewater from operation of the facility flows to the refinery's collection and treatment system. LSPI is not affiliated with the refinery and does not support or share raw materials and products. The operations of LSPI are not associated with, are not under common control with, and belong to a different SIC Code Major Grouping than the refinery. Therefore, LSPI is not included in the refinery's Title V permit.

III.3 OSU-University Multi-Spectral Laboratory

SIC Code 8733 – Noncommercial Research Organizations (Major Group 87: Engineering, Accounting, Research, Management, and Related Services). The Oklahoma State University Multi-Spectral Laboratory (OSU-UML) is an Oklahoma Not-for-Profit, Limited Liability Company created as a wholly owned subsidiary of OSU. The OSU-UML is located in the building formerly known as the Research & Development East facility on the Ponca City Refinery complex. Operation of the facility is contracted by OSU to American Manufacturing and Technologies, Inc. (AMTI). Because the building is located on refinery-owned property, process wastewater from operation of the facility flows to the refinery's collection and treatment system. The personnel, management, and fiscal decision-making relative to the UML are separate from those same functions at the refinery. The employees responsible for the facility are not refinery employees and cannot be disciplined by the refinery manager. In summary, this facility is not under common control with and does not belong to the same SIC Code Major Grouping as the refinery. Therefore, the UML is not included in the refinery's Title V permit.

III.4 Jupiter Sulfur LLC (JSLLC)

SIC Code 2873 - Nitrogenous Fertilizers (Major Group 28: Chemicals and Allied Projects). JSLLC owns a sulfur/nitrogen fertilizer production facility that is located next to the refinery. JSLLC Ponca City facility processes "acid gasses" (primarily H2S)—a portion of which are purchased from the Phillip 66 refinery—into various products including Elemental Sulfur, Ammonium Thiosulfate Solution, Ammonium Polysulfide Solution, and Ammonium Sulfide Solution. Phillips 66 owns a 50 percent interest in JSLLC. JSLLC employs Tessenderlo Kerly, Inc. (TKI) as the operator of the facility. TKI is responsible for management, operation, and maintenance of the facility. The structure and operation of the Jupiter facility are independent of the refinery, since there is outside ownership and operation.

Consent Order No. 00-196, which was filed on July 11, 2000, contains the following language in Attachment C, Section VIII.D for compliance measures dealing with NSR/PSD Analysis Methodology: "Based upon DEQ's review of information provided by Conoco related to the Jupiter facility, Jupiter shall be excluded from this methodology description as a separate stationary source."

The Jupiter facility currently operates under a synthetic minor air permit. On August 10, 2016, however, the DEQ issued to Jupiter an Applicability Determination, 91-034-AD (M-6), in which DEQ determined that the Jupiter facility is part of the adjacent Phillips 66 refinery for MACT purposes, and that as part of a facility subject to MACT major source requirements, Jupiter is also subject to Title V operating permit requirements. In response to a source determination request from Jupiter, EPA agreed with DEQ's Applicability Determination as documented in letters dated June 10, 2020, and December 21, 2021. The Jupiter facility is not included in the refinery's Title V permit application, but emissions from the facility will be aggregated for NSR/PSD and NESHAP applicability purposes. The JSLLC is operating under a separate Title V major source operating permit, Permit No. 2022-0436-TV (M-1), issued on January 15, 2025.

III.5 South Tank Farm

SIC Code 4612 – Crude Petroleum Pipelines (Major Group 46 – Pipelines, Except Natural Gas). The South Tank Farm is comprised of eighteen (18) tanks, most of which are separated from the refinery by fencing, although three tanks (T-629, T-630, and T-631) are located just within the refinery side of the fenceline. These tanks receive crude oil via pipeline from Cushing, OK. The tanks are dedicated to the refinery (they do not act as "terminal" tanks to ship crude to other locations), and some South Tank Farm tanks feed directly to refinery process units. However, all of this tankage is owned and operated by Phillips 66 Midstream Division. The personnel, management, and fiscal decision-making relative to these tanks are separate from those same functions at the refinery. The employees responsible for the tanks are not refinery employees and cannot be disciplined by the refinery manager. Although the South Tank Farm is not under common control with and belongs to a different SIC Code Major Grouping than the refinery, operation of the tankage is contiguous with the refinery. The South Tank Farm is not included in the refinery's Title V permit application, but emissions from the facility will be aggregated for NSR/PSD and NESHAP applicability purposes. The South Tank Farm is operated under Permit No. 2018-1651-TVR2, issued on August 21, 2020.

III.6 Ponca City Products Terminal

SIC Code 5171 - Gasoline & Oil Bulk Stations (Wholesale) (Major Grouping 51: Wholesale Trade – non-durable goods). The Ponca City Truck Rack is located southwest of the main refinery operations and generally south of the refinery tank farm. This facility serves to load refinery products out to tanker trucks which then make deliveries to commercial or retail customers. The truck rack consists of tanks, pumps, and truck loading equipment. All of this equipment is operated by personnel of Phillips 66 Midstream Division. The personnel, management, and fiscal decision-making relative to these tanks are separate from those same functions at the refinery. The employees responsible for the tanks are not refinery employees and cannot be disciplined by the refinery manager. Although the truck rack is not under common control with and belongs to a different SIC Code Major Grouping than the refinery, operation of the truck rack is contiguous with the refinery. The Ponca City Truck Rack is not included in the refinery's Title V permit

application, but emissions from the facility will be aggregated for NSR/PSD and NESHAP applicability purposes. The Ponca City Products Terminal is operated under Permit No. 2018-1651-TVR2, issued on August 21, 2020.

III.7 Cherokee Pump Station

SIC Code 4612 – Crude Petroleum Pipelines (Major Group 46 – Pipelines, Except Natural Gas). The Cherokee Pump Station (CPS) is a pipeline pumping station that ships finished products, including gasoline, out of the refinery through pipelines to various terminals. Most of the equipment related to the operations is located outside of the refinery fenceline, and within a discrete area dedicated to these operations, located to the southwest of the main refinery operations. There are approximately five pumps that are located on the refinery side of the fenceline near the product tanks. All of this equipment is operated by personnel of Phillips 66 Midstream Division. Inherently low sulfur gas streams from pipeline pigging and other routine maintenance activity is vented to the refinery's flare Flare-CC. The personnel, management, and fiscal decision-making relative to these tanks are separate from those same functions at the refinery. The employees responsible for the tanks are not refinery employees and cannot be disciplined by the refinery manager. Although the CPS is not under common control with and belongs to a different SIC Code Major Grouping than the refinery, operation of the CPS is contiguous with the refinery. The CPS is not included in the refinery's Title V permit application, but emissions from the facility will be aggregated for NSR/PSD and NESHAP applicability purposes. The CPS is operated under Permit No. 2018-1651-TVR2, issued on August 21, 2020.

III.8 Warren Petroleum Company Lease

SIC Code 1311 – Crude Petroleum and Natural Gas (Major Group 13 – Oil & Gas Extraction). The Warren Petroleum Company lease consists of 2 crude tanks, 2 saltwater tanks, and associated crude oil pumping equipment. This equipment is physically located within the refinery fenceline but the equipment is not associated with refinery operations. Warren Petroleum Company owns, operates, and maintains the equipment. In summary, this equipment is not associated with, is not under common control with, and does not belong to the same SIC Code Major Grouping as the refinery. Therefore, the Warren Petroleum Company Lease is not included in the refinery's Title V permit.

III.9 Groundwater Recovery/Containment Wellfield

The Groundwater Recovery/Containment Wellfield, located inside and outside the fenceline of the refinery, consists of groundwater pumping and containment equipment. Recovered groundwater and product are pumped to the refinery's slop recovery and wastewater treatment systems. Emissions from the operation of groundwater remediation wells are considered to be an insignificant activity under OAC 252:100 Appendix I. This equipment is operated and maintained by refinery personnel, however, management, and fiscal decision-making relative to this equipment are handled by Phillips 66 Remediation Management Business Unit, which is separate from those same functions at the refinery. It is unclear whether these activities should be aggregated with the refinery for the purposes of Title V permitting. This remedial activity is exempt from NESHAP Subpart GGGGG since it is permitted under RCRA. There are no other federal requirements related to Air Quality associated with these activities so their inclusion in the refinery's Title V permit will not be of issue. Therefore, the Groundwater Recovery/Containment Wellfield activities are included the refinery's Title V permit as "Insignificant Activities."

III.10 4th Street Clubhouse SVE System

The 4th Street Clubhouse Soil Vapor Extractor (SVE) System is a site remediation activity located on the east edge and outside the fenceline of the refinery. The SVE System equipment is considered to be contiguous to the refinery because the equipment is operated and maintained by refinery personnel and fiscal decision-making is managed by the same entity. The SVE System is independent of refinery operations and is not considered a refinery process unit. The 4th Street Clubhouse SVE System is included in the refinery's Title V permit.

SECTION IV. FACILITY DESCRIPTION

In 1911, E. W. Marland purchased land south of the Ponca City town-site and built the Marland Refining Company refinery, which is now the Phillips 66 Company Ponca City Refinery. A small skimming plant began operating in 1914, which was designed to process oil into gasoline, kerosene, and naphtha. Marland Refining Company merged with Continental Oil Company in 1929 and the merged company became known as the Continental Oil Company. By this time more complex equipment had been added to the refinery and the plant was capable of processing 27,000 barrels of crude oil per day. In 1943, the aviation gasoline facility was built by the Defense Plant Corporation of the U.S. government and was operated during World War II by Continental Oil Company. After the war, Continental Oil Company purchased and integrated the aviation gasoline facility into the refinery, which is the present-day South Plant area. The Sequoia (former Cities Services until 1966) refinery was purchased in 1970, which is the present-day East Plant area. In 1979, the company name was changed to Conoco Inc. Conoco Inc. merged with and became a wholly owned subsidiary of E. I. DuPont de Nemours Company, Inc. in 1981, but became an independent company again in 1999. In 2003, Conoco Inc. merged with Phillips Petroleum Company to form ConocoPhillips Company. In 2012, ConocoPhillips Company split into two separate companies, ConocoPhillips Company and Phillips 66 Company, the latter of which includes the Ponca City Refinery. The facility's refining capacity at the time of this permit is approximately 203,000 barrels per day of crude oil.

The facility is divided into six main areas based on the layout of the operations: East Plant, West Plant, North Plant, South Plant, Coker Combo/Alky, and Oil Movements. The facility converts crude oil into a variety of saleable products such as liquid fuels, LP gas, and feedstocks for other industries. Primary process units include crude distillation units, a saturate gas plant, catalytic reforming units, an isomerization unit, hydrodesulfurization units, hydrotreating units, merox units, a bender unit, amine units, fluid catalytic cracking units, a coker unit, an alkylation unit, and catalytic polymerization unit. Saleable products are blended in the gasoline blending, diesel blending, and jet fuel blending processes. Auxiliary equipment includes emergency flares, steam boilers, hydrogen plants, fuel gas recovery systems, cooling towers, sour water treatment units, activated sludge and other wastewater treatment systems, intermediate and product storage, coke loading, and liquid hydrocarbon loading.

The following is a general explanation of unit operations at the Refinery.

IV.1 Crude Oil

Approximately 99 percent of the crude oil to be processed at the Ponca City Refinery arrives via pipelines.

IV.2 Distillation

Distillation is the process of boiling a liquid and collecting the condensed vapor. In petroleum refining, distillation is used to separate crude oil into more useful components. A tall tower called a fractionating column is used to distill the crude oil. As crude enters the column, the lighter, lower boiling point components vaporize and rise to a level where the surrounding temperature and pressure correspond to their boiling point. Meanwhile, heavier, higher boiling point components descend in a liquid stream to a level where conditions match their boiling point. The column is filled with trays containing holes, which allow the ascending vapor to bubble through the descending liquid, increasing contact between the two phases. The vapors are cooled, condensed and drawn off as distillates at various points up the column – gas oil first, then diesel, kerosene, naphtha and finally, petroleum gases such as propane and butane. The heavy oils that are not vaporized because of their very high boiling points are piped off from the bottom of the tower.

IV.3 Cracking

Cracking is used to convert the heavier gas oils into more valuable products. This is done by breaking down the complex molecule chains which make up the heavier hydrocarbon compounds into simpler, lighter ones. There are three different types of cracking:

- Thermal cracking using heat alone.
- Fluid catalytic cracking using heat in the presence of a catalyst, which enhances the chemical conversion without itself being changed. This has certain advantages over thermal cracking in giving higher gasoline yields, while the lighter gases produced can be used as feed for alkylation.
- Hydrocracking using heat and catalyst plus hydrogen. This has an advantage when there is a need to produce diesel rather than gasoline.

IV.4 Alkylation

Alkylation is the opposite of cracking. Instead of breaking down larger hydrocarbon molecules into smaller ones, alkylation units convert two smaller molecules into one larger one to produce alkylate, a high-octane gasoline-blending component.

IV.5 Desulfurization

Increased processing of high-sulfur crudes, coupled with the need for greater product blending flexibility and ever tighter fuel specifications (largely due to environmental considerations) has driven the development of treating technology to remove sulfur compounds and other impurities from oil feedstock and petroleum products.

Hydrodesulfurization uses hydrogen to remove sulfur compounds by converting them into hydrogen sulfide in the presence of a catalyst. The hydrogen sulfide produced is removed from the product gas stream by an amine wash and converted into elemental sulfur and fertilizer for sale to the public and chemical industry.

IV.6 Reforming

Naphtha produced by some refinery processes, such as crude distillation or thermal cracking, does not have a high enough octane rating for direct use. However, it can be modified in a catalytic reformer to convert low-octane molecules into high-octane molecules.

IV.7 Coking

The Refinery utilizes delayed coking to upgrade heavy oil to petroleum coke and more valuable lighter products. Heavy oil feedstock from the bottom of the coker fractionator is heated in a furnace where it begins to crack into liquid and vapor mixture. This flows to the coke drums where solid petroleum coke forms and hydrocarbon vapors are released. The coke remains in the drum, solidifies and gradually fills the vessel. The vapors are returned to the fractionator where high-value products are recovered. When the coke drum is full, it is taken out of service and the other drum is put on. The full drum is taken out of service and a pilot hole is drilled in the coke bed. A horizontal water cutting tool is inserted through the pilot hole and breaks the coke into large chunks, which fall into rail cars. The empty drum is sealed, steamed and put into service again.

IV.8 Products

Petroleum products are delivered to customers by pipeline, rail, and road (trucks). The vast majority of products from the Refinery are delivered by pipeline to distribution terminals in the mid-continent region of the United States. Intermediate and finished products are stored in more than 150 tanks, bullets, and spheres. Some finished products are produced directly from the process units, such as propane and jet fuels. However, gasoline and diesel fuel products are blended to the required specifications before being stored in product tanks and subsequently distributed to customers. Green anode petroleum coke is stored on a small pad in the refinery and delivered to customers by truck.

SECTION V. PROJECT DESCRIPTIONS

V.1 PONCA CITY REFINERY 2020-2022 LONG-RANGE PLAN PROJECT

The items included in Permit No. 2012-704-C (M-11), i.e., the 2020-2022 LRP Project, and listed in the permit modification application are scheduled to occur within the same contemporaneous time period. The applicant has requested to permit them as if they are one project.

The 2020-2022 LRP Project and the items included in the permit modification application will include, among other things, numerous energy efficiency improvement items such as replacement of old compressors and pumps with new equipment, and replacement and modification of heat exchangers to improve heat recovery. Specific details of the individual project elements are described in the following pages.

V.1.1 Reserved

V.1.2 MODIFIED - No. 4 FCCU Yield Improvements and Reliability

The applicant proposes to replace the existing No. 4 Fluidized Catalytic Cracking Unit (FCCU) converter with a new converter and associated equipment to improve product yields and equipment reliability. The new converter will include the following:

- a new riser and new feed nozzle module to enhance feed distribution;
- a new disengager/reactor vessel with a closed coupled riser termination system, new primary and secondary cyclones, and a more efficient catalyst stripper; and
- a new regenerator vessel with new cyclones, air distribution grid, and spent catalyst distributor to improve catalyst regeneration.
- installation of a chiller for the main air blower inlet which will result in a change in the future projected unit feed rate from 30,000 barrels per day (BPD) to 27,000 BPD.

The converter technology improvements are intended to result in the following changes to the unit yield pattern:

- increase propylene and butylene (PBs) production;
- increase isobutene production;
- increase gasoline production;
- reduce light cycle oil (LCO) production; and
- increase decant/slurry oil production.

The additional butylene and isobutene will be sent to the Ponca City Refinery hydrofluoric-acid (HF) Alkylation Unit to make more alkylate for gasoline blending. The additional propylene will be sent to either the HF Alkylation Unit or to propylene sales. The incremental decant/slurry oil will be sent either to the Ponca City Refinery Delayed Coking Unit or to decant sales.

The converter technology changes will also allow the unit to process vacuum resid in the gas oil feed and by doing so avoid resid sales that are currently necessary due to existing refinery constraints.

The existing No. 4 FCCU hot gas oil feed pumps will be replaced to improve equipment reliability. In addition, the turbine driver for one of the hot gas oil feed pumps will be replaced with a motor to reduce steam consumption.

The No. 4 FCCU refrigeration system compressor motor is at end-of-life and the Ponca City Refinery has determined that it is more cost effective to replace the motor with a new machine than to try to repair the existing equipment. The Ponca City Refinery has also determined that the starter and wiring for the existing 1,000-HP motor can accommodate a 1,250-HP motor and that there is only a marginal cost difference between the two sizes. Therefore, the Ponca City Refinery proposes to replace the existing equipment motor with a 1,250-HP motor. There currently are no plans to make design changes to the refrigeration system compressor in order to increase its capacity.

The Ponca City Refinery will also increase the size of the No. 4 FCCU debutanizer tower pressure relief valve and raise the set pressures of the No. 4 FCCU main fractionator tower pressure relief valves. As a result of these changes, the safe operating limit (SOL) charge rate for the No. 4 FCCU is expected to be 27,000 BPD. A relief system study was performed to ensure the capacity of the pressure relief valves, flare header, and other flare system components is sufficient to accommodate the potential increase.

No. 4 FCCU Yield Improvements and Reliability

Unit	Source Description	Project Impact on Emissions Unit	Project Impact on Permit
No. 4 FCCU	Fugitive Emissions	Addition of new fugitive components (piping, valves, flanges, etc.).	Increased VOC emissions from fugitive components.

V.1.3 HF Alkylation Unit Expansion

The Ponca City Refinery proposes to increase the capacity of the HF Alkylation (Alky) by implementing the following unit modifications.

V.1.3.1 Reserved

V.1.3.2 Reserved

V.1.3.3 Alky Unit Heat Exchanger Maintenance Improvement

The Ponca City Refinery proposes to replace the eight existing Alky Unit depropanizer tower overhead condensers to improve maintenance capability of these critical heat exchangers.

The depropanizer tower overhead condensers experience significant fouling which prevents the bundles from being pulled from their shells during mechanical turnarounds. Typically, the heat exchangers must be sent off-site to have the shells split in order to extract the bundles. This cycle of splitting and re-welding the shells has been repeated numerous times over the past several years and has resulted in the heat exchanger shells becoming out-of-round which further exacerbates the bundle extraction problem. The Ponca City Refinery proposes to replace all eight overhead condensers with new shells and bundles which will be designed with increased shell to baffle clearances to ensure the ease of future bundle extraction.

V.1.3.4 Alky Unit Merox Improvements

The Ponca City Refinery proposes to replace the existing Alky Unit Propane-Propylene (PP) Merox extraction tower which has reached end-of-life. The existing Butane-Butylene (BB) Merox extraction tower will be repurposed as the PP Merox extractor tower and a new BB Merox extractor tower will be installed.

In addition to the new BB Merox extractor tower, piping, and instrumentation, the Ponca City Refinery proposes to also install a new, larger PP Merox feed cooler and new level indication instrumentation for existing drums including the two caustic prewash drums, the sand filter drum, and the caustic prewash settler which will also be equipped with a Coalex coalescer. These changes will increase the capacity of the BB Merox system and minimize caustic carryover.

HF Alkylation Unit Expansion – Affected Emission Units

Unit	Source Description	Project Impact on Emissions Unit	Project Impact on Permit
HF Alky Unit	Fugitive Emissions	Addition of new fugitive components (piping, valves, flanges, etc.).	Increased VOC emissions from fugitive components and the new cooling tower.

V.1.4 Reserved

V.1.5 No. 5 Gas Oil Hydrotreater Reactor Replacement

The Ponca City Refinery proposes to install a new larger hydrotreating reactor in the No. 5 Gas Oil Hydrotreater (GOHDT) and abandon the existing reactor in its current location. The current No. 5 GOHDT total feed includes all of the heavy coker gas oil (HCGO) and enough No. 1 CTU heavy vacuum gas oil (HVGO) to fill the unit. At the beginning of the catalyst cycle (i.e., the time period between catalyst change outs) the No. 5 GOHDT processes the maximum amount of HVGO up to a hydraulic constraint. As the cycle progresses, the catalyst deactivates and the reactor inlet temperature necessary to maintain treated product stream quality increases. In order to maintain the desired reactor inlet temperature, the amount of cold HVGO feed must continually be reduced until the catalyst is completely deactivated. The new reactor will contain a greater catalyst volume which will, in turn, extend the catalyst cycle and enable treating a greater volume of HVGO before reductions are required due to catalyst deactivation. The cycle length, as dictated by catalyst deactivation, is expected to increase from 1 year to 2 years.

The new reactor will not change the feed rate to the downstream No. 5 FCCU. Instead, the new reactor will increase the percentage of gas oil treated in the No. 5 GOHDT, which will improve the quality of the No. 5 FCCU total feed. Specifically, it will increase the saturation of aromatics in the treated gas oil stream which "cracks" better in the No. 5 FCCU resulting in higher conversion of feed into gasoline.

No. 5 Gas Oil Hydrotreater Reactor Replacement

Unit	Source Description	Project Impact on Emissions Unit	Project Impact on Permit
No. 5 GOHDT	Fugitive Emissions	Addition of new fugitive components (piping, valves, flanges, etc.).	Increased VOC emissions from fugitive components.

V.1.6 C5/C6 Molecule Management

Processing of light crude oils in recent years at the Ponca City Refinery has resulted in increased production of Light Straight Run (LSR) which is a mixture of pentanes (C5s) and hexanes (C6s) or other hydrocarbon molecules that boil at similar boiling points. To process the entire volume of LSR that is produced and improve clean product yields, the Ponca City Refinery proposes to increase the capacities of the No. 2 CTU LSR product pump, the Saturate Gas Plant (SGP) LSR charge pumps, the LSR Hydrotreater (No. 7 HDT), and the Isomerization (Isom) Unit. The No. 7 HDT capacity expansion will include replacement of the existing feed pumps and feed/effluent

exchangers, installing a new product pump, and increasing the permitted annual fired duty limit of unit charge heater H-0011 from 15 MMBtu/hr to 18 MMBtu/hr. Lastly, the Isom Unit expansion will include installation of a third Penex Reactor. These modifications are intended to enable the Ponca City Refinery to lift LSR out of naphtha being fed to the catalytic reformers and into the No. 7 HDT and Isom units.

C5/C6 Molecule Management

Unit	Source Description	Project Impact on Emissions Unit	Project Impact on Permit
No. 2 CTU	Fugitive Emissions	Addition of new fugitive components (piping, valves, flanges, etc.).	Increased VOC emissions from fugitive components.
Sat Gas Plant			
No. 7 HDT			
Isom Unit			
No. 7 HDT	Combustion Source Emissions	Increase the fired duty limit for charge heater H-0011	Increased SO_2, NO_X, CO, $PM_{10/2.5}$, and VOC from charge heater H-0011

V.1.7 No. 2 CTU Crude vs. Heating Oil Distillate and Kerosene vs. Raw Crude Heat Exchanger Replacements

The Ponca City Refinery proposes to replace the No. 2 CTU crude oil versus heating oil distillate (HOD) heat exchanger X-6036 and relocate the equipment to a new position in the crude oil preheat exchanger train. The intended result of these changes is to improve recovery of heat into crude oil which will, in turn, increase the inlet temperatures to No. 2 CTU preflash tower reboiler H-6015, atmospheric furnace H-6005, and vacuum furnace H-6014 in a cascading effect. Because the furnaces essentially operate at their fired duty limits, the result will be a marginal increase in the outlet temperatures from the atmospheric and vacuum furnaces, which will generate more "lift" and will redistribute products from the heavy oils to the light oils (e.g., more diesel will be lifted out of the gas oil into the diesel product draw and more gas oil will be lifted out of the resid into the gas oil draw).

Replacement of No. 2 CTU heat exchanger X-6036 will increase the temperature of the crude oil entering kerosene versus raw crude heat exchanger X-6302 which will, in turn, reduce the cooling of kerosene in the heat exchanger. Therefore, the Ponca City Refinery proposes to also replace heat exchanger X-6302 with larger equipment in order to increase heat transfer from kerosene to raw crude, thus allowing the kerosene product to be adequately cooled for storage.

The new heat exchangers will not increase the No. 2 CTU throughput but by improving heat transfer they will improve the separation of intermediate oils.

No. 2 CTU Crude vs. Heating Oil Distillate and Kerosene vs. Raw Crude Heat Exchanger Replacements

Unit	Source Description	Project Impact on Emissions Unit	Project Impact on Permit
No. 2 CTU	Fugitive Emissions	Addition of new fugitive components (piping, valves, flanges, etc.).	Increased VOC emissions from fugitive components.

V.1.8 Reserved

V.1.9 Separate Diesel Rundown Streams

The unit throughput of the No. 9 cracked diesel HDT is currently limited by the ability to pump product to storage. In order to overcome this limitation, the Ponca City Refinery proposes to install two No. 9 HDT diesel product booster pumps. The Ponca City Refinery also proposes to remove the restriction orifice in the No. 6 virgin diesel HDT product line in order to allow additional throughput for the unit.

Following these changes, the Ponca City Refinery will have the ability to segregate the rundown of the No 6 HDT and No. 9 HDT diesel product streams. Segregation of the product streams will enable the Ponca City Refinery to blend naphtha into diesel in order to reduce flash point giveaway on diesel product sales in addition to increasing refinery diesel hydrotreating capacity.

Separate Diesel Rundown Streams

Unit	Source Description	Project Impact on Emissions Unit	Project Impact on Permit
No. 9 HDT	Fugitive Emissions	Addition of new fugitive components (piping, valves, flanges, etc.).	Increased VOC emissions from fugitive components.

V.1.10 Improve No. 8 HDT Reliability

The Ponca City Refinery currently feeds FCCU gasoline and virgin naphtha to the No. 8 HDT and the product stream from the unit is sent to the Ponca City Refinery gasoline product pool. The Ponca City Refinery proposes to add jumper lines to feed naphtha from the Top Flex LSR-Naphtha splitter tower and the No. 9 HDT to the No. 8 HDT feed drum in lieu of virgin naphtha. The octane value of the Top Flex and No. 9 HDT naphtha streams, which are currently routed to storage and then to the Ponca City Refinery catalytic reforming units (CRUs), is greater than that of the virgin naphtha currently fed to the No. 8 HDT. Replacing the virgin naphtha with the Top Flex and No. 9 HDT naphtha streams will increase the octane value of the gasoline pool and allow the Ponca City Refinery to reduce the operating severity of the CRUs which will, in turn, increase gasoline yield by reducing cracking. Also, preferentially sending naphtha streams with lower chloride content to the No. 8 HDT will help reduce exchanger fouling.

Improve No. 8 HDT Reliability

Unit	Source Description	Project Impact on Emissions Unit	Project Impact on Permit
No. 8 HDT	Fugitive Emissions	Addition of new fugitive components (piping, valves, flanges, etc.).	Increased VOC emissions from fugitive components.

V.1.11 Reserved

V.1.12 Reserved

V.1.13 Reserved

V.1.14 No. 4 CTU Product Stream Flow Rates

The Ponca City Refinery proposes that the flow rate limits for the No.4 CTU/CVU product streams, including light straight run gasoline, naphtha, kerosene, heating oil distillate, total gas oil, and resid, be removed as listed in the current Title V permit.

In 2002, Permit No. 2002-115-C was issued to the Ponca City Refinery for the No. 4 CTU/CVU Expansion project. For the permit application, the Ponca City Refinery calculated the emissions increases resulting from the No. 4 CTU/CVU and sources associated with the project by first estimating the future actual flow rates for the No. 4 CTU/CVU product streams. The projected flow rates were then used to estimate the emissions increases from the downstream associated sources.

V.1.15 Storage Tank Annual Average True Vapor Pressure

The following tanks are subject to annual average true vapor pressure limits included in the Ponca City Refinery's current Title V permit.

Storage Tank Vapor Pressure Limits

Tank	Service	Annual Average (psia)
T-0014E	Naphtha	4.200
T-0015	Naphtha	4.200
T-107E	Gas Oil	0.160
T-0117	Naphtha	4.200
T-0120	Gas Oil	0.100
T-0122	Gas Oil	0.039
T-0123	Diesel	0.039
T-0124	Diesel	0.039
T-0125	Diesel	0.039
T-0126	Diesel	0.039
T-0128	Kerosene	0.039
T-0129	Diesel	0.039
T-0130	Diesel Oil	0.039
T-0131	Diesel	0.039

Tank	Service	Annual Average (psia)
T-0135	Diesel Oil	0.039
T-0136	Diesel	0.039
T-0253	Spent Caustic/HC	2.200
T-0254	Spent Caustic/HC	2.200
T-0509	Spent Caustic/HC	2.200

Tanks T-0014E, T-0015, and T-0117 are subject to 40 CFR Part 60, New Source Performance Standards (NSPS) Subpart Kb and MACT Subpart CC as Group 1 storage vessels. In addition to the true vapor pressure limits listed in the table above, the tanks are also subject to the following limits:

Additional Permit Limits for Tanks T-0014E, T-0015, and T-0117

Tank	Throughput Limit (gal/yr)[1]	VOC Limit (TPY)[2]	Calendar Month Average Vapor Pressure Limit (psia)
T-0014E	4,003,000	6.6	<11.1
T-0015			<11.1
T-0117	636,384,000	15.8	<11.1

1. 12-month rolling total.
2. Calendar year total unless otherwise specified.

The annual average true vapor pressure limits listed in the table beginning on Page 17 serve no additional purpose not already provided by the limits summarized in the table above. As such, the Ponca City Refinery proposes that the annual average true vapor pressure limits for tanks T-0014E, T-0015, and T-0117 be removed from the current Title V permit. This request was granted and addressed in Permit No. 2012-704-C (M-3).

Tanks T-0107E, T-0120, T-0122, T-0123, T-0124, T-0125, T-0126, T-0128, T-0129, T-0130, T-0131, T-0135, T-0136, T-0253, T-0254 and T-0509 are subject to MACT Subpart CC as Group 2 storage vessels. In addition to the true vapor pressure limits listed in the table beginning on Page 18, the tanks are also subject to the following limits:

Additional Permit Limits for Tanks T-0107E, T-0120, T-0122, T-0123, T-0124, T-0125, T-0126, T-0128, T-0129, T-0130, T-0131, T-0135, T-0136, T-0253, T-0254 and T-0509

Tank	Throughput Limit (gal/yr)[1]	VOC Limit (TPY)[2]	Calendar Month Average Vapor Pressure Limit (psia)
T-0107E	291,270,000	20.6	0.5
T-0120	919,800,000	23.7	-
T-0122	5,631,000,000[3]	155[3]	-
T-0123			-
T-0124			-
T-0125			-
T-0126			-
T-0128			-
T-0129			-
T-0130			-
T-0131			-
T-0135			-
T-0136			-
T-0253	26,280,000	-	-
T-0254	26,280,000	-	-
T-0509		-	-

1. 12-month rolling total.
2. Calendar year total unless otherwise specified.
3. Also includes tanks T-0173 and T-0186.

None of the tanks listed in the table above contain material having an average HAP content greater than 4 wt%. As such, the tanks are not subject to the MACT Subpart CC vapor pressure limits for Group 1 storage vessels.

The annual average true vapor pressure limits listed in the table beginning on Page 17 serve no additional purpose not already provided by the limits summarized in the table above. As such, the Ponca City Refinery proposes that the annual average true vapor pressure limits for tanks T-0107E, T-0120, T-0122, T-0123, T-0124, T-0125, T-0126, T-0128, T-0129, T-0130, T-0131, T-0135, T-0136, T-0253, T-0254 and T-0509 be removed from the current Title V permit. This request was granted and addressed in Permit No. 2012-704-C (M-3).

V.1.16 Reserved

V.1.17 No. 2 Crude Topping Unit (CTU) Desalter Booster Pump P-6304 Impeller and Flow Control Valve Replacement

The No. 2 CTU crude oil preheat exchanger train splits into two passes downstream of the unit desalter. One pass recovers heat from gas oil (GO)/heating oil distillate (HOD) to desalted crude oil and the other pass recovers heat from resid. When the No. 2 CTU is operating at full rates, the temperature of the desalted crude oil from the resid preheat pass is approximately 100°F less than the desalted crude oil from the GO/HOD preheat pass primarily because of the capacity of desalted crude booster pump P-6304.

The maximum impeller size for pump P-6304 is 21-inches. Several years ago, the impeller for pump P-6304 was trimmed to 19-inches in order to reduce electrical energy usage. The smaller impeller also reduced the pump capacity, consequently limiting the overall capacity of the No. 2 CTU, specifically limiting the flow of crude oil through the GO/HOD preheat pass. Installing a full-sized impeller will increase the capacity of pump P-6304 which will, in turn, enable more crude oil flow to be directed through the GO/HOD preheat pass, improving preheat train heat recovery. The increased heat recovery will, in turn, allow the No. 2 CTU to process additional crude oil (approximately 620 BPD annual average) with no increased furnace fired duties.

The proposed project will also replace the resid preheat pass flow control valve with a larger valve to improve control. No incremental fugitive emissions will occur because of the No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement modification.

Additionally, this project includes the addition of two 16-inch isolation valves and two 4-inch isolation valves at the No. 2 CTU. These valves will be placed between the preheat train and the preflash tower, allowing for parallel clearing of this equipment and overall more expeditious decoking of the No. 2 CTU. Decoking occurs every other year, and this project could result in an extra 12 hours of operation during those years. The project potentially allows for an extra 30 BPD at the No. 2 CTU.

V.1.18 No. 5 FCCU Diesel Recovery Improvement

The No. 5 FCCU Main Fractionator tower currently experiences flooding and reduced separation efficiencies at high feed rates which results in lighter ranged FCCU light cycle oil (LCO) material being pushed into the FCCU gasoline stream. LCO is characterized as diesel material produced from cracking reactions and is fed to the No. 9 HDT. The Ponca City Refinery proposes to replace the existing Main Fractionator tower packing and trays with new, high efficiency packing in order to improve LCO recover.

The No. 5 FCCU LCO air cooler currently operates with excessive pressure drop which limits LCO production. The Ponca City Refinery proposes to replace the No. 5 FCCU LCO air cooler with larger equipment in order to reduce pressure drop and increase diesel product draw from the unit main fractionator tower.

No. 5 FCCU Diesel Recovery Improvements

Unit	Source Description	Project Impact on Emissions Unit	Project Impact on Permit
No. 5 FCCU	Fugitive Emissions	Addition of new fugitive components (piping, valves, flanges, etc.).	Increased VOC emissions from fugitive components.

V.1.19 Coker Unit Furnace Uptime Improvements and On-Line Spalling

In recent years, changes in crude and resid properties have resulted in accelerated fouling of the Ponca City Refinery Delayed Coking (Coker) unit furnaces, shorter runs between furnace decokes, and a reduction in the total volume of resid and slurry that the Coker Unit can process. In order to address these issues, the Ponca City Refinery proposes to install equipment to enable on-line

spalling of the existing Coker furnaces (spalling is the removal of coke deposits from the inside of furnace tube walls using high velocity steam or boiler feed water while thermally contracting and expanding the tubes). Improving the Coker Unit uptime will increase the overall average calendar day feed capacity by approximately 1,200 BPD.

The increased Coker Unit capacity will be used to process additional FCCU decant/slurry oil and convert it to clean product. A portion of the additional decant/slurry oil will come from running resid in the No. 4 FCCU (see Subsection V.1.2) and the balance will come from reduced sales.

As part of this item, the Ponca City Refinery will also install new distillation trays in the Coker Unit bubble/fractionation tower. The existing trays are old technology that is no longer available, i.e., obsolete, and experience "weeping" (liquid escaping from the trays through the vapor passageways). The proposed replacement trays will be more resistant to fouling. No incremental fugitive emissions will occur because of the Coker Unit Furnace Uptime Improvements and On-Line Spalling project.

V.1.20 Reserved

V.1.21 Reserved

V.1.22 Reserved

V.1.23 No. 1 Crude Topping Unit Utilization Project

The No. 1 Crude Topping Unit (No. 1 CTU) runs six (6) years between maintenance turnarounds. During this six-year cycle, the unit is shut down twice to decoke furnaces and clean heat exchangers. In addition, the unit reduces rate for approximately 14 days every year to clean select heat exchanges on-line.

This project adds isolation valves and bypasses around several existing exchangers to facilitate on-line cleaning. In addition, the project installs three (3) new heat exchangers which improve the transfer of product stream heat to crude oil feed. These changes will eliminate one decoke during the six-year cycle and the annual rate reductions required to clean exchangers. This will increase the barrels of crude oil processed during a calendar year by approximately 1,245 BPD.

No. 1 CTU Utilization Project

Unit	Source Description	Project Impact on Emissions Unit	Project Impact on Permit
No. 1 CTU	Fugitive Emissions	Addition of new fugitive components (piping, valves, flanges, etc.).	Increased VOC emissions from fugitive components.

V.1.24 Olefin Recovery from FCC Gasoline

FCC gasoline is currently hydrotreated in the No. 8 Hydrotreater (No. 8 HDT) and then divided into two (2) streams: Light Cat Naphtha (LNC) and Heavy Cat Naphtha (HCN). LCN contains butylenes and isobutane which are left in the FCC gasoline due to constraints in the existing FCC debutanizers. Approximately 11,000 BPD of LCN is sent to the LCN Debutanizer tower (W-42)

to remove the butylenes/isobutane which are then routed to the HF Alkylation unit (Alky) for conversion to high octane alkylate.

This project will implement the following changes in order to increase the feed rate of LCN to W-42 from 11,000 BPD to 18,000 BPD.

- Install new No. 8 HDT LCN booster pumps;
- Replace the W-42 bottoms pumps;
- Replace the W-42 feed/overhead heat exchanger bundle and channel in order to achieve a higher design pressure;
- Reconfigure the W-42 feed/bottoms heat exchanger from four (4) pass to two (2) pass; and
- Install a new GC analyzer to measure the W-42 overhead composition.

In addition, the HF Alky butane rundown line piping and heat exchangers will be replaced with larger equipment in order to mitigate butane hydraulic constraints.

Olefin Recovery from FCC Gasoline

Unit	Source Description	Project Impact on Emissions Unit	Project Impact on Permit
No. 8 HDT	Fugitive Emissions	Addition of new fugitive components (piping, valves, flanges, etc.).	Increased VOC emissions from fugitive components.
W-42			
HF Alky			

V.2 PONCA CITY SOUTH TANK FARM EXPANSION PROJECT

In addition to the items proposed for the Ponca City Refinery, Phillips 66 proposes to implement a project, referenced to as the Ponca City South Tank Farm (STF) Expansion Project, that will increase the capacity of the STF to supply crude oil feedstock to the Ponca City Refinery. Specifically, the STF Expansion Project will increase the flow rate of crude oil to the Ponca City Refinery by an average of 833 BPD

The scope of the proposed STF Expansion Project is:

- Of the 12 existing STF blend pumps:
  - Replace two of the blend pumps with new in-kind equipment;
  - Install full-sized (13-inch) impellers in the remaining ten (10) blend pumps; and
  - Replace the seven (7) 30-hp and four 40-hp blend pump motors with 50-hp motors. Also replace the existing starters and install new conduit and warning for the new motors.
- Install one new 125-hp booster pump and motor and associated piping. Also install a new electric pole, pad-mounted transformer, main breaker, and wiring for the new motor.
- Install a new pressure relief valve and line from downstream of the blend pumps back to the tanks. This valve will not relieve (be vented) to the atmosphere.
- Replace all positive displacement (PD) meters with Coriolis meters.
- Install a new electrical breaker and wiring for the increased load.
- Replace approximately 2,000 feet of 6-inch piping located downstream of the No. 4 Crude Topping Unit (CTU) crude pumps going to and from an existing crude metering station

which an estimated 350 feet of 10-inch piping. Also, new crude meters will be installed closer to the new crude pumps.

In addition to the modifications to be made by this project to STF equipment, the existing Refinery pumps that deliver crude oil from the STF to the No. 4 CTU will be replaced with higher-capacity equipment. Implementation of the STF Expansion Project is scheduled to occur within the same contemporaneous window as the items included in Permit No. 2012-704-C (M-11) and the permit modification application.

The Ponca City Refinery is currently operating under Permit No. 2012-704-TVR (M-16), issued on January 23, 2025, and the STF is currently operating under Permit No. 2018-1651-TVR2, issued on August 21, 2020. However, because the STF and the Ponca City Refinery are considered collocated and part of a single facility site for the purpose of emissions evaluation and regulatory applicability, emissions increases associated with the STF Expansion Project are included in this permit modification (see Section VI.3.4). To authorize the proposed modifications of STF Expansion Project, Phillips 66 has applied for a major source construction permit for their Ponca City Pipeline Activities facility. The application for the Ponca City Pipeline Activities was processed as Permit No. 2018-1651-C (M-1).

The baseline period for the 2020-2022 LRP construction permit application and initial update was January 1, 2016, through December 31, 2017, for NO_X, SO_2, CO, and VOC and August 1, 2016, to July 31, 2018, for PM_{10} and $PM_{2.5}$. However, in order to properly account for emissions resulting from the STF Expansion Project, including Refinery No. 1 CTU furnace H-0001 which began operation on November 6, 2017, January 1, 2018, through December 31, 2019, was selected as the baseline period for this permit modification application update for all criteria pollutants.

South Tank Farm Expansion

Unit	Source Description	Project Impact on Emissions Unit	Project Impact on Permit
STF	Fugitive Emissions	Addition of new fugitive components (piping, valves, flanges, etc.).	Increased VOC emissions from fugitive components.

SECTION VI. PROJECT EMISSIONS

This section presents the emission calculation methodology used to determine PSD applicability for new, modified, and associated units, including process heaters, FCCUs, and equipment leaks.

VI.1 EMISSION INCREASE TEST METHODS

OAC 252:100-8-30(b)(3) through (6) describe test methods for determining if significant emission increases have occurred, requiring further PSD analysis.

> *(3)* ***Actual-to-projected-actual applicability test for projects that only involve existing emissions units.*** *A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions and the baseline*

actual emissions for each existing emissions unit, equals or exceeds the amount that is significant for that pollutant.

(4) ***Actual-to-potential test for projects that only involve construction of a new emissions unit(s).*** *A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit from each new emissions unit following completion of the project and the baseline actual emissions of these units before the project equals or exceeds the amount that is significant for that pollutant.*

(5) ***Hybrid test for projects that involve multiple types of emission units.*** *A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emission increases for each emissions unit, using the method specified in OAC 252:100-8-30(b)(3) or (4) as applicable with respect to each emissions unit, for each type of emissions unit equals or exceeds the amount that is significant for that pollutant. [For example, if a project involves both an existing emissions unit and a new emissions unit, the projected increase is determined by summing the values determined using the method specified in OAC 252:100-8-30(b)(3) for the existing unit and the values determined using the method specified in OAC 252:100-8-30(b)(4) for the new emissions units.]*

(6) ***Actual-to-potential test for projects that only involve existing emissions units.*** *In lieu of using the actual-to-projected-actual test, owners or operators may choose to use the actual-to-potential test to determine if a significant emissions increase of a regulated NSR pollutant will result from a proposed project. A significant emissions increase of a regulated NSR pollutant will occur if the sum of the difference between the potential emissions and the baseline actual emissions for each existing emissions unit, equals or exceeds the amount that is significant for that pollutant. Owners or operators who use the actual to potential test will not be subject to the recordkeeping requirements in OAC 252:100-8-36.2(c).*

The Ponca City Refinery will use the following test(s) as allowed under OAC 252:100-8-30(b)(5) to evaluate emission increases resulting from the proposed projects:

- Existing associated process units and equipment and equipment that will be replacements of existing equipment:
    - Actual-to-projected-actual applicability test for projects that only involve existing emissions units described in OAC 252:100-8-30(b)(3).
- New Equipment:
    - Actual-to-potential test for projects that only involve construction of new emissions units described in OAC 252:100-8-30(b)(4).
- Existing equipment whose permitted limits are to be increased:
    - Actual-to-potential test for projects that only involve existing emissions units described in OAC 252:100-8-30(b)(6).

The baseline actual emissions for the sources affected by Permit No. 2012-704-C (M-11) and the permit modification application for this permit are based on the most representative operating data for a consecutive 24-month period during the previous 10 years. A baseline period of January 1,

2018, through December 31, 2019, was selected for this permit modification for NO_X, CO, VOC, SO_2, $PM_{10/2.5}$ and H_2S emissions. A baseline period of January 1, 2016, through December 31, 2017, was selected for this permit modification for GHG emissions.

VI.2 DETERMINING NET EMISSIONS

In the PSD review process, a six-step procedure (summarized below) was used for determining the net emissions change.

1. **Emission Increases from the Project** – Determine the emissions increases from the project, including any associated emissions increases (i.e., debottlenecking emissions). On August 1, 2019, the U.S. Environmental Protection Agency (EPA) proposed a rule that would amend the New Source Review (NSR) applicability regulations to clarify that both emissions increases and decreases which are part of a project may be considered in Step 1[1] of the NSR major modification applicability test. The EPA had previously explained in a memorandum dated March 13, 2018[2], that it interprets the current NSR regulations as providing that emissions decreases as well as increases from a major modification are to be considered in Step 1 of the NSR applicability process. The final rule was published on November 24, 2020[3]. Per the direction of the March 2018 memorandum and the November 2020 final rule, if the sum of emission increases and decreases from the project are above PSD Significant Emission Rates (SERs), proceed; if not, the project is not subject to PSD review.
2. **Contemporaneous Period** – Determine the beginning and ending dates of the contemporaneous period as it relates to the project.
3. **Emission Increases and Decreases during the Contemporaneous Period** – Determine which emissions units at the facility experienced or will experience a creditable increase or decrease in emissions during the contemporaneous period.
4. **Creditable Emissions Changes** – Determine which contemporaneous emissions changes are creditable.
5. **Amount of the Emissions Increases and Decreases** – Determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease.
6. **PSD Review** – Sum all contemporaneous and creditable increases and decreases with the emissions changes from the project to determine if a significant net emissions increase will occur.

VI.3 EMISSIONS INCREASES FROM THE PROJECTS

In this step, emissions increases from the sources affected by Permit No. 2012-704-C (M-11) and this permit modification application were calculated on a pollutant-by-pollutant basis. The emissions increases include both project emissions and emissions from sources associated with the project. Emission decreases from the project are considered in this step.[4]

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[1] The EPA currently refers to Step 1 applicability procedures as "project emissions accounting" (previously known as "project netting") and Step 2 as "contemporaneous netting."

[2] Letter from E. Scott Pruitt, to Regional Administrators, "Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program," March 13, 2018.

[3] 85 Fed. Reg. 74890-74909 (November 24, 2020).

[4] Ibid

For a conservative analysis, $PM_{2.5}$ is assumed to be equivalent to PM_{10}, and emissions increases of PM_{10} will be compared to the $PM_{2.5}$ SER of 10 TPY rather than the PM_{10} SER of 15 TPY.

VI.3.1 New Emissions Units

VI.3.1.1 Fugitive Emissions

VI.3.1.1.1 2020-2022 Long-Range Plan Project

The 2020-2022 LRP Project will result in increased fugitive VOC emissions from equipment such as flanges and valves. For the purpose of the PSD applicability emissions analyses, the VOC emission increases associated with the 2020-2022 LRP Project were calculated using the number of fugitive components estimated to be added by the individual projects. The emissions increases for equipment leaks were calculated using design-basis fugitive counts along with emission factors that were developed specifically for the Ponca City Refinery.[5] The following table summarizes the VOC emission increases for the 2020-2022 LRP Project resulting from fugitive elements.

Summary of Project Potential VOC Emission Increases

Project Element	Modified Sources	VOC (TPY)
No. 4 FCCU Yield Improvement and Reliability	Fugitives	0.1
HF Alkylation Unit Expansion	Fugitives	1.6
No. 5 Hydrotreater Reactor Replacement	Fugitives	<0.1
C5/C6 Molecule Management	Fugitives	4.0
No. 2 CTU Crude vs. Heating Oil Distillate and Kerosene vs. Raw Crude Heat Exchanger Replacements	Fugitives	<0.1
Segregate Diesel Rundown Streams	Fugitives	0.7
Improve No. 8 Hydrotreater Reliability	Fugitives	1.0
No. 5 Fluidized Catalytic Cracking Unit Diesel Recovery Improvement	Fugitives	0.3
No. 1 CTU Utilization Project	Fugitives	0.3
Olefin Recovery from FCC Gasoline	Fugitives	2.5
No. 2 CTU Desalter Booster Pump P-6304 Impeller and Flow Control Valve Replacement and Isolation Valves	Fugitives	0.1
Total		**10.6**

VI.3.1.1.2 South Tank Farm Expansion Project

The STF Expansion Project will result in increased fugitive VOC emissions from equipment such as flanges, valves, and pumps. For the purpose of the PSD applicability analyses, the VOC emission increases associated with the STF expansion Project were calculated using the number of fugitive components estimated to be added by the project. The emissions increases for

[5] The emission factors are the "permit quality" emission factors for new sources at the Ponca City Refinery referenced in the March 1, 1991, and March 9, 1991, correspondence to Oklahoma Air Quality Service.

equipment leaks were calculated using design-basis fugitive counts along with emission factors that were developed specifically for the Ponca City Refinery.[6]

Summary of Project Potential VOC Emission Increases

Project Element	Modified Sources	VOC (TPY)
South Tank Farm Expansion Project	Fugitives	0.9
Total		**0.9**

VI.3.1.2 Reserved

VI.3.1.3 Reserved

VI.3.2 Reconstructed/Replacement Emission Units

VI.3.2.1 FCCUs

VI.3.2.1.1 No. 4 FCCU

The 2020-2022 LRP Project will replace the existing No. 4 FCCU converter (see Subsection V.1.2). Emissions from the replacement converter were estimated as follows.

VI.3.2.1.1.1 Projected Actual Coke Burn

The projected actual No. 4 FCCU coke burn was estimated using the future estimated SOL gas oil feed rate of 27,000 BPD (see Subsection V.1.2) and a coke burn factor of 13.57 lb/bbl feed. Due to existing limitations of unit processing equipment (pumps, control valves, etc.) that will not be addressed as part of the 2020-2022 LRP project, it is not certain if the No. 4 FCCU will be able to achieve a feed rate of 27,000 BPD, but the SOL is considered a conservative estimate of the unit future operation and so was used as the basis for estimating the projected actual coke burn.

The coke burn factor was established taking into account the technology improvements that will be included with the replacement converter. The feed nozzles will be designed to achieve the appropriate steam-to-gas oil feed which will improve feed atomization and distribution which will, in turn, improve both heat transfer and feed vaporization and in doing so reduce liquid hydrocarbon to catalyst contact time and so reduce coke yield. The closed coupled cyclones will also shorten the regenerator catalyst bed dilute phase residence time which will reduce the occurrence of undesirable thermal cracking which can also affect coke make.

V.3.3.2.1.2 Projected Actual $PM_{10/2.5}$ Emissions

The projected actual No. 4 FCCU $PM_{10/2.5}$ emissions were estimated using a factor of 0.06 lb/1,000 lb of coke burn which is the average value for the unit during the baseline period between January 1, 2018, and December 31, 2019. Emissions were determined to be less than the emissions during the baseline actual period. Therefore, for the sake of conservatism, the projected actual emissions of PM for the No. 4 FCCU were set equal to the baseline actual values.

[6] Ibid

V.3.3.2.1.3 Projected Actual NO_X, CO, and SO_2 Emissions

The projected actual No. 4 FCCU NO_X, CO, and SO_2 emissions were estimated using a flue gas factor of 184 dry standard cubic feet (DSCF)/lb of coke burn, a NO_X concentration of 30 ppmv, an SO_2 concentration of 3 ppmv, and a CO concentration of 95 ppmv, all of which were the average values for the unit during the time period between January 1, 2018, and December 31, 2019.

V.3.3.2.1.4 Projected Actual VOC Emissions

The projected actual No. 4 FCCU VOC emissions were estimated using a factor of 0.075 lb of VOC/lb of CO. The following table presents the emissions for the No. 4 FCCU.

No. 4 FCCU Emissions

Pollutant	Actual Emissions		Baseline Actual Emissions[(1)]	Projected Actual Emissions
	2018	2019		
	TPY	TPY	TPY	TPY
CO	85.9	77.2	81.5	85.0
PM/PM_{10}	3.7	5.1	4.4	4.4
NO_X	43.4	37.5	40.4	44.1
SO_2	7.7	4.6	6.2	6.2
VOC	6.4	5.8	6.1	6.4
GHG	229,523	198,264	213,893	240,966

VI.3.2.1.2 No. 5 FCCU

VI.3.2.1.2.1 Projected Actual Coke Burn

The projected actual No. 5 FCCU coke burn was estimated using a unit gas oil feed rate of 39,931 BPD and coke burn factor of 14.09 lb/bbl feed. The gas oil feed rate is the average rate since startup of the unit following the mechanical turnaround (39,005 BPD) plus an additional 336 BPD of gas oil feed estimated to result from the No. 5 Hydrotreater Reactor Replacement, the Coker Unit Furnace Uptime Improvements and On-Line Spalling items (see Sections IV.1.5 and IV.1.19, respectively), an additional 363 BPD of gas oil feed estimated to result from the No. 1 CTU Utilization Project item (see Subsection V.1.23), and an additional 227 BPD of gas oil feed estimated to result from the South Tank Farm Expansion item (see Subsection V.2). The coke burn factor is the average value for the unit during the time periods between January 1, 2018, and December 31, 2019.

VI.3.2.1.2.2 Projected Actual CO Emissions

The projected actual CO emissions were estimated based on a BACT CO limit of 150 ppmvd, corrected to 0% O_2, a molecular weight of 28.01 lb/lb-mol for CO, an air blower rate of 325,000 lb/hr (i.e., 72,222 scfm), a molar volume of 385.326 scf/lb-mol. This results in a CO emission rate of 47.2 lb/hr, or 206.7 TPY.

VI.3.2.1.2.3 Projected Actual $PM_{10/2.5}$ Emissions

The projected actual No. 5 FCCU $PM_{10/2.5}$ emissions were estimated using a factor of 0.48 lb/1,000 lb of coke burn which is the average value for the unit during the baseline actual period between January 1, 2018, and December 31, 2019.

VI.3.2.1.2.4 Projected Actual NO_X, SO_2, and VOC Emissions

The projected actual No. 5 FCCU NO_X, CO, and SO_2 emissions were estimated using a flue gas factor of 178 DSCF/lb of coke burn, a NO_X concentration of 21 ppmv, an SO_2 concentration of 3.8 ppmv, a CO concentration of 150 ppmv, and a VOC concentration of 1.72 ppmv, all of which were the average values for the unit during the time period between January 1, 2018, and December 31, 2019. The following table presents the emissions for the No. 5 FCCU.

No. 5 FCCU Emissions

Pollutant	Actual Emissions		Baseline Actual Emissions(1)	Projected Actual Emissions
	2018	2019		
	TPY	TPY	TPY	TPY
CO	32.2	30.5	31.3	206.7
PM/PM_{10}	58.2	38.7	48.5	49.3
NO_X	50.4	39.9	45.1	45.8
SO_2	11.8	10.5	11.1	11.6
VOC	2.4	3.4	2.9	3.6
GHG	358,993	352,295	355,644	355,644

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.2.2 Reserved

VI.3.3 Permit Limit Changes to Existing Emission Units

The emissions increases from existing equipment undergoing physical changes whose permitted limits are to be increased as a result of the 2020-2022 LRP Project and South Tank Farm Expansion Project were calculated on a pollutant-by-pollutant basis using the actual-to-potential test described in OAC 252:100-8-30(b)(6) for a conservative demonstration.

VI.3.3.1 Process Heaters

The 2020-2022 LRP Project will increase the permitted operating limits for the emissions units summarized in the following table.

Project	Associated Emissions Unit	EU ID	Description
2020-2022 LRP Project	No. 4 CTU	H-0003	Topped Crude Furnace
		H-0004	Crude Furnace
	No 7 HDT	H-0011	Charge Heater

The 2020-2022 LRP Project and the South Tank Farm Expansion Project do not include physical modifications to any of the above listed furnaces.

VI.3.3.1.1 No. 4 CTU Topped Crude Furnace H-0003

VI.3.3.1.1.1 Proposed Fired Duty Limit

The project will result in an increase in crude oil feed to the No. 4 CTU. This increase in feed will require a corresponding increase in the permitted annual fired duty limit for topped crude furnace H-0003 to 32.0 MMBtu/hr.

VI.3.3.1.1.2 Proposed NO_X and CO Emission Limits

The proposed permitted NO_X and CO emission limits for heater H-0003 were estimated by multiplying the currently permitted emissions (TPY) by the ratio of the proposed fired duty limit divided by the current fired duty limit.

VI.3.3.1.1.3 Proposed SO_2 Emission Limit

The proposed permitted SO_2 emission limit for heater H-0003 as estimated assuming the fuel gas H_2S concentration of 60 ppmv and the proposed fired duty limit.

VI.3.3.1.1.4 Proposed $PM_{10/2.5}$ and VOC Emission Limits

The proposed permitted $PM_{10/2.5}$ and VOC emission limits for heater H-0003 were estimated using emission factors from AP-42 (7/98) Section 1.4 for criterial pollutants from natural gas combustion and the proposed fired duty limit. The following table presents the parameters and emissions for heater H-0003.

Heater H-0003 Parameters and Emissions

EU ID	Currently Permitted Firing Rate	Projected Potential Firing Rate	Pollutant	Currently Permitted Emissions	Baseline Actual Emissions (1)	Potential Emissions	
	MMBtu/hr	MMBtu/hr		TPY	TPY	lb/hr	TPY
H-0003	28.0	32.0	CO	4.8	4.4	1.3	5.5
			PM_{10}	-	0.8	0.2	1.0
			NO_X	12.1	9.0	3.2	13.8
			SO_2	3.8	0.4	0.3	1.4
			VOC	-	0.6	0.2	0.8
			GHG	-	11,848	3,503	15,341

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.3.1.2 No. 4 CTU Crude Furnace H-0004

VI.3.3.1.2.1 Proposed Fired Duty Limit

The project will result in an increase in crude oil feed to the No. 4 CTU. This increase in feed will require a corresponding increase in the permitted annual fired duty limit for topped crude furnace H-0004 to 118 MMBtu/hr.

VI.3.3.1.2.2 Proposed CO Emission Limits

The proposed permitted CO emission limits for heater H-0004 were estimated by multiplying the currently permitted emissions (TPY) by the ratio of the proposed fired duty limit divided by the current fired duty limit.

VI.3.3.1.2.3 Projected Actual NO_X Emissions

The proposed permitted NO_X emission limits for heater H-0004 were estimated by multiplying the proposed fired duty limit by an emission factor of 0.127 lb/MMBtu (0.110 lb/MMBtu plus a 1.15 safety factor) based on recent stack testing.

VI.3.3.1.2.4 Projected Actual SO_2 Emissions

The proposed permitted SO_2 emission limit for heater H-0004 was estimated assuming a fuel gas H_2S concentration of 60 ppmv and the proposed fired duty limit.

VI.3.3.1.2.5 Projected Actual $PM_{10/2.5}$ and VOC Emissions

The proposed permitted $PM_{10/2.5}$ and VOC emission limits for heater H-0004 were estimated using emission factors from AP-42 (7/98) Section 1.4 for criterial pollutants from natural gas combustion and the proposed fired duty limit. The following table presents the parameters and emissions for heater H-0004.

Heater H-0004 Parameters and Emissions

EU ID	Currently Permitted Firing Rate	Projected Potential Firing Rate	Pollutant	Currently Permitted Emissions	Baseline Actual Emissions (1)	Potential Emissions	
	MMBtu/hr	MMBtu/hr		TPY	TPY	lb/hr	TPY
H-0004	106	118	CO	18.1	18.5	4.6	20.1
			PM_{10}	-	3.5	0.9	3.9
			NO_X	69.6	54.9	15.0	65.6
			SO_2	14.4	1.7	1.2	5.1
			VOC	-	2.5	0.6	2.8
			GHG	-	48,456	12,667	55,483

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.3.1.3 No. 7 Hydrotreater Charge Heater H-0011

VI.3.3.1.3.1 Proposed Fired Duty Limit

The C5/C6 Molecule Management and the South Tank Farm Expansion items (see Subsections V.1.6 and V.2, respectively) will, among other things, result in an increase in the feed rate to the No. 7 HDT. This increase in feed will require a corresponding increase in the fired duty for the topped crude furnace H-0011 to 18 MMBtu/hr.

VI.3.3.1.3.2 Proposed NO_X and CO Emission Limits

The proposed permitted NO_X and CO emission limits for heater H-0011 were estimated by multiplying the currently permitted emissions (TPY) by the ratio of the proposed fired duty limit divided by the current fired duty limit.

VI.3.3.1.3.3 Proposed SO_2 Emission Limit

The proposed permitted SO_2 emission limit for heater H-0011 was estimated assuming a fuel gas H_2S concentration of 60 ppmv and the proposed fired duty limit.

VI.3.3.1.3.4 Proposed $PM_{10/2.5}$ and VOC Emission Limits

The proposed permitted $PM_{10/2.5}$ and VOC emission limits for heater H-0011 were estimated using emission factors from AP-42 (7/98) Section 1.4 for criterial pollutants from natural gas combustion

and the proposed fired duty limit. The following table presents the parameters and emissions for heater H-0011.

Heater H-0011 Parameters and Emissions

EU ID	Currently Permitted Firing Rate	Projected Potential Firing Rate	Pollutant	Currently Permitted Emissions	Baseline Actual Emissions (1)	Potential Emissions	
	MMBtu/hr	MMBtu/hr		TPY	TPY	lb/hr	TPY
H-0011	15	18	CO	5.4	2.4	1.5	6.5
			PM_{10}	0.5	0.4	0.1	0.6
			NO_X	7.9	5.8	2.2	9.5
			SO_2	7.5	0.1	0.2	0.8
			VOC	1.3	0.3	0.1	0.4
			GHG	--	7,303	2,224	9,741

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.3.1.4 Reserved

VI.3.4 Associated Emission Units

Associated emissions are included for the purpose of verifying PSD applicability or non-applicability and air quality modeling, if necessary. The associated emission units will continue to operate in compliance with currently applicable rules, regulations, and permit conditions. Therefore, the Ponca City Refinery requests that this permit modification not include emission limits or specific conditions for the associated emission units. The following table summarizes the emission units associated with the items included in Permit No. 2012-704-C (M-11), the 2020-2022 LRP Project updates of this permit modification, and the South Tank Farm Expansion Project.

Summary of Associated Emission Units

Associated Emission Unit	Item	EU ID	Description
No. 1 CTU	No. 1 CTU Utilization Project, and South Tank Farm Expansion	H-0001	Crude Heater
		H-0016	Vacuum Heater
Saturated Gas Plant	No. 1 CTU Utilization Project, No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement, C5/C6 Molecule Management, and South Tank Farm Expansion	H-0010	Naphtha Stabilizer Reboiler

Associated Emission Unit	Item	EU ID	Description
No. 8 HDT	No. 1 CTU Utilization Project, No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement, Coker Unit Furnace Uptime Improvement and On-Line Spalling, No. 5 Hydrotreater Reactor Replacement, C5/C6 Molecule Management, No. 2 CTU Crude vs. Heating Oil Distillate and Kerosene vs. Raw Crude heat exchanger replacements, C5/C6 Molecule Management, and South Tank Farm Expansion	H-8601	Splitter Reboiler
		H-8602	Feed Heater
No. 9 HDT	No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement, Coker Unit Furnace Uptime Improvement and On-Line Spalling, and No. 2 CTU Crude vs. Heating Oil Distillate and Kerosene vs. Raw Crude heat exchanger replacements	H-9901	Feed Heater
		H-9902	Stripper Reboiler
No. 2 H2 Plant	Coker Unit Furnace Uptime Improvement and On-Line Spalling, No. 5 Hydrotreater Reactor Replacement, and C5/C6 Molecule Management	H-9851	Reformer
Benzene Reduction	No. 1 CTU Utilization Project, No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement, C5/C6 Molecule Management, and South Tank Farm Expansion	H-9301	Reformate Splitter Reboiler
No. 3 CRU	No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement, and C5/C6 Molecule Management	H-6007	Reformer Main Furnace
		H-6012	Desulfurizer Furnace
		H-6013	Reheat Furnace

Associated Emission Unit	Item	EU ID	Description
No. 4 FCCU	No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement, No. 4 FCCU Yield Improvements and Reliability, and No. 2 CTU Crude vs. Heating Oil Distillate and Kerosene vs. Raw Crude heat exchanger replacements	H-6151	Preheat Furnace
No. 5 HDT	No. 1 CTU Utilization Project, No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement, No. 5 Hydrotreater Reactor Replacement, and South Tank Farm Expansion	H-0023	Reactor Charge Heater
No. 7 Coker	No. 1 CTU Utilization Project, Coker Unit Furnace Uptime Improvements and On-Line Spalling, and South Tank Farm Expansion	H-0028	Coker Process Heater
		H-0029	Coker Process Heater
		Coke Drum Vent	Coke Drum Vent
		Coke Cutting	Coke Cutting
		Water Handling	Water Handling
		Coke Pile	Coke Pile
No. 2 CRU	No. 1 CTU Utilization Project, Coker Unit Furnace Uptime Improvements and On-Line Spalling, and South Tank Farm Expansion	H-0046	HDS Furnace
		H-0048	Reformer Furnace
No. 6 HDT	No. 1 CTU Utilization Project, No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement, No. 2 CTU Crude vs. Heating Oil Distillate and Kerosene vs. Raw Crude heat exchanger replacements, and South Tank Farm Expansion	H-7501	Reactor Charge Heater
No. 5 FCCU	No. 1 CTU Utilization Project, Coker Unit Furnace Uptime improvements and On-Line Spalling, No. 5 Hydrotreater Reactor Replacement, and South Tank Farm Expansion	No. 5 FCCU	Regenerator
		H-5002	Preheat Furnace

Associated Emission Unit	Item	EU ID	Description
Oil Movements	No. 4 FCCU Yield Improvements and Reliability, HF Alkylation Unit Expansion, Coker Unit Furnace Uptime Improvements and On-Line Spalling, No. 5 Hydrotreater Reactor Replacement, C5/C6 Molecule Management, No. 2 CTU Crude vs. Heating Oil Distillate and Kerosene vs. Raw Crude heat exchanger replacements, Improved No. 8 Hydrotreater Reliability, Segregate Diesel Rundown Streams	T-0125	Diesel Storage Tank
		T-0165	Alkylate Storage Tank
		T-0166	Gasoline Storage Tank
Wastewater Treatment System	No. 1 CTU Utilization Project, and	Tanks	Wastewater Streams
Ponca City Pipeline Activities	No. 1 CTU Utilization Project, South Tank Farm Expansion	Tanks	South Tank Farm Crude Oil Storage Tanks, Cherokee Pump Station, and Ponca City Products Terminal
		Fugitives	
		Loading Racks	

The emission increases for associated sources resulting from the 2020-2022 LRP Project and this permit modification were calculated on a pollutant-by-pollutant basis using the actual-to-projected-actual test described in OAC 252:100-8-30(b)(3). As a result, the Ponca City Refinery will be subject to the monitoring and recordkeeping requirements of OAC 252:100-8-36.2(c) for 10 years following resumption of regular operations after completion of the proposed project and because the project increases the potential to emit (PTE) of the facility.

In order to properly account for emissions resulting from the STF Expansion Project, including Refinery No. 1 CTU furnace H-0001 which began operation on November 6, 2017, a baseline period of January 1, 2018, through December 31, 2019, was selected for all criteria pollutants.

It should be noted that the projected fired duties for a number of the furnaces associated with the 2020-2022 LRP Project and the South Tank Farm Expansion Project were less than their past actual fired duties. As such, for the sake of conservatism, the projected actual fired duties for the following heaters were set equal to the baseline actual values.

EU ID	Baseline Actual Firing Rate [1]	Projected Actual Firing Rate
	MMBtu/hr	MMBtu/hr
H-0029	45.4	42.2
H-0046	33.8	24.2
H-0048	216.6	207.5
H-6007	120.4	112.6
H-6012	22.9	21.9
H-6013	52.2	45.3
H-6151	44.1	43.4
H-7501	23.6	19.7
H-8602	16.6	16.0
H-9901	29.0	29.0
H-9301	105.4	91.5

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.1 Associated Emissions Units – Process Heaters

The following summarizes the methodologies used to estimate the projected actual emissions for process heaters associated with the 2020-2022 LRP Project and the South Tank Farm Expansion Project.

VI.3.4.1.1 Saturated Gas Plant Naphtha Stabilizer Reboiler H-0010

VI.3.4.1.1.1 Projected Actual Fired Duty

The C5/C6 Molecule Management, No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement, No. 1 CTU Utilization Project, and the South Tank Farm Expansion items (see Subsections V.1.6, V.1.17, V.1.23, and V.2, respectively) will, among other things, result in an increase in flow to Saturated Gas Plant naphtha stabilizer tower W-8. This increase in flow is estimated to increase the fired duty of naphtha stabilizer reboiler H-0010 to 53.1 MMBtu/hr.

VI.3.4.1.1.2 Projected Actual NO_X, $PM_{10/2.5}$, SO_2, and VOC Emissions

The projected actual NO_X, $PM_{10/2.5}$, SO_2, and VOC emissions for heater H-0010 were estimated by multiplying the baseline actual emissions (TPY) by the ratio of the projected actual fired duty divided by the baseline actual fired duty.

VI.3.4.1.1.3 Projected Actual CO Emissions

The projected actual CO emissions for heater H-0010 were estimated by multiplying the projected actual fired duty by an assumed emission factor of 0.04 lb/MMBtu. The following table presents the parameters and emissions for heater H-0010.

Heater H-0010 Parameters and Emissions

EU ID	Baseline Actual Firing Rate (1)	Projected Actual Firing Rate	Pollutant	Baseline Actual Emissions(1)	Projected Actual Emissions	
	MMBtu/hr	MMBtu/hr		TPY	lb/hr	TPY
H-0010	44.3	53.1	CO	7.8	2.1	9.3
			PM_{10}	1.4	0.4	1.7
			NO_X	19.0	5.2	22.8
			SO_2	0.7	0.2	0.9
			VOC	1.0	0.3	1.3
			GHG	19,904	5,447	23,858

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.1.2 No. 8 Hydrotreater Splitter Reboiler H-8601 and Feed Heater H-8602

VI.3.4.1.2.1 Projected Actual Fired Duty

The No. 5 Gas Oil Hydrotreater Reactor Replacement, C5/C6 Molecule Management, No. 2 CTU Crude vs. Heating Oil Distillate and Kerosene vs. Raw Crude heat exchanger replacements, No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement, Coker Unit Furnace Uptime Improvement and On-Line Spalling, No. 1 CTU Utilization Project, and South Tank Farm Expansion items (see Subsections V.1.5, V.1.6, V.1.7, V.1.17, V.1.19, V.1.23, and V.2, respectively) will, among other things, increase production of gasoline feed to the No. 8 Hydrotreater. This increase in flow is estimated to increase the fired duty of splitter reboiler H-8601 to 107.5 MMBtu/hr.

The projected actual fired duty for feed heater H-8602 was estimated to be less than the baseline actual fired duty of 16.6 MMBtu/hr. As such, for the sake of conservatism, the projected actual fired duty for heater H-8602 was set equal to the baseline actual value.

VI.3.4.1.2.2 Projected Actual NO_X, $PM_{10/2.5}$, SO_2, and VOC Emissions

The projected actual NO_X, SO_2, VOC, and $PM_{10/2.5}$ emissions for heater H-8601 were estimated by multiplying the baseline actual emissions (TPY) by the ratio of the projected actual fired duties divided by the baseline actual fired duties.

The projected actual NO_X, $PM_{10/2.5}$, SO_2, and VOC emissions for heater H-8602 were set equal to the baseline actual values.

VI.3.4.1.2.3 Projected Actual CO Emissions

The projected actual CO emissions for heater H-8601 were estimated by multiplying the projected actual fired duties by an assumed emission factor of 0.04 lb/MMBtu. The projected actual CO emissions for heater H-8602 were set equal to the baseline values. The following table presents the parameters and emissions for heaters H-8601 and H-8602.

Heaters H-8601 and H-8602 Parameters and Emissions

EU ID	Baseline Actual Firing Rate (1)	Projected Actual Firing Rate	Pollutant	Baseline Actual Emissions(1)	Projected Actual Emissions	
	MMBtu/hr	MMBtu/hr		TPY	lb/hr	TPY
H-8601	83.3	107.5	CO	15.5	4.3	18.8
			PM_{10}	2.8	0.8	3.6
			NO_X	8.0	2.4	10.3
			SO_2	1.4	0.4	1.8
			VOC	2.1	0.6	2.7
			GHG	40,422	12,249	53,652
H-8602	16.6	16.6	CO	2.9	0.7	2.9
			PM_{10}	0.5	0.1	0.5
			NO_X	2.2	0.5	2.2
			SO_2	0.3	0.1	0.3
			VOC	0.4	0.1	0.4
			GHG	7,480	1,708	7,480

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.1.3 No. 9 Hydrotreater Feed Heater H-9901 and Stripper Reboiler H-9902

VI.3.4.1.3.1 Projected Actual Fired Duty

The No. 2 CTU Crude vs. Heating Oil Distillate and Kerosene vs. Raw Crude heat exchanger replacements, No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement, and Coker Unit Furnace Uptime Improvement and On-Line Spalling items (see Subsections V.1.7, V.1.17, and V.1.19, respectively) will, among other things, increase production of diesel oil feed to the No. 9 Hydrotreater. This increase in flow is estimated to increase the fired duty of stripper reboiler H-9902 to 30.0 MMBtu/hr.

The projected actual fired duty for feed heater H-9901 was estimated to be less than the baseline actual fired duty of 29.0 MMBtu/hr. As such, for the sake of conservatism, the projected actual fired duty for heater H-9901 was set equal to the baseline actual value.

VI.3.4.1.3.2 Projected Actual NO_X, $PM_{10/2.5}$, SO_2, and VOC Emissions

The projected actual NO_X, $PM_{10/2.5}$, SO_2, and VOC emissions for heater H-9902 were estimated by multiplying the baseline actual emissions (TPY) by the ratio of the projected actual fired duty divided by the baseline actual fired duty.

The projected actual NO_X, $PM_{10/2.5}$, SO_2, and VOC emissions for heater H-9901 were set equal to the baseline actual values.

VI.3.4.1.3.3 Projected Actual CO Emissions

The projected actual CO emissions for heaters H-9901 and H-9902 were estimated by multiplying the projected actual fired duties by an assumed emission factor of 0.04 lb/MMBtu. The following table presents the parameters and emissions for heaters H-9901 and H-9902.

Heaters H-9901 and H-9902 Parameters and Emissions

EU ID	Baseline Actual Firing Rate (1)	Projected Actual Firing Rate	Pollutant	Baseline Actual Emissions(1)	Projected Actual Emissions	
	MMBtu/hr	MMBtu/hr		TPY	lb/hr	TPY
H-9901	29.0	29.0	CO	5.1	1.2	5.1
			PM_{10}	0.9	0.2	0.9
			NO_X	2.3	0.5	2.3
			SO_2	0.5	0.1	0.5
			VOC	0.6	0.1	0.6
			GHG	16,737	3,867	16,939
H-9902	27.1	30.0	CO	4.7	1.2	5.3
			PM_{10}	0.9	0.2	1.0
			NO_X	2.2	0.6	2.4
			SO_2	0.4	0.1	0.4
			VOC	0.6	0.2	0.7
			GHG	15,620	3,964	17,361

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.1.4 No. 2 Hydrogen Plant Reformer H-9851

VI.3.4.1.4.1 Projected Actual Fired Duty

The No. 5 Hydrotreater Replacement, and C5/C6 Molecule Management, and Coker Unit Furnace Uptime Improvement and On-Line Spalling items (see Subsections V.1.5, V.1.6, and V.19 respectively) will, among other things, result in an increase in consumed hydrogen (H_2) by various Refinery process units. The Ponca City Refinery currently has a surplus of H_2 that is "vented off" to fuel gas. Some of this H_2 will be recovered and the balance of the estimated increased H_2 volume will be produced by the No. 2 Hydrogen Plant. The resulting projected actual fired duty for No. 2 Hydrogen Plant Reformer H-9851 is 270.4 MMBtu/hr.

VI.3.4.1.4.2 Projected Actual NO_X, $PM_{10/2.5}$, SO_2, and VOC and Emissions

The projected actual NO_X, $PM_{10/2.5}$, SO_2, and VOC emissions for heater H-9851 were estimated by multiplying the baseline actual emissions (TPY) by the ratio of the projected actual fired duty divided by the baseline actual fired duty.

VI.3.4.1.4.3 Projected Actual CO Emissions

Because it is equipped with a stack CO continuous emissions monitoring system (CEMS) the projected actual CO emissions for heater H-9851 were estimated by multiplying the baseline actual emissions (TPY) by the ratio of the projected actual fired duty divided by the baseline actual fired duty. The following table presents the parameters and emissions for heater H-9851.

Heater H-9851 Parameters and Emissions

EU ID	Baseline Actual Firing Rate (1)	Projected Actual Firing Rate	Pollutant	Baseline Actual Emissions(1)	Projected Actual Emissions	
	MMBtu/hr	MMBtu/hr		TPY	lb/hr	TPY
H-9851	212.0	245	CO	3.8	1.0	4.4
			PM_{10}	6.8	1.8	7.9
			NO_X	28.6	7.5	33.1
			SO_2	1.7	0.4	2.0
			VOC	2.6	0.7	3.0
			GHG	51,850	13,700	60,008

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.1.5 Benzene Fractionation Unit Reformate Splitter Reboiler H-9301

VI.3.4.1.5.1 Projected Actual Fired Duty

The C5/C6 Molecule Management, No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement, No. 1 CTU Utilization Project, and South Tank Farm Expansion items (see Subsections V.1.6, V.1.17, V.1.23, and V.2, respectively) will, among other things, result in an increase in reformate production at the facility which will, in turn, result in a decrease in the Benzene Fractionation Unit (BFU) splitter reboiler fired duty. In addition, the C5/C6 Molecule Management item will increase removal of benzene precursors (cyclohexane and methyl cyclopentane) from reformer feed, resulting in less benzene formation which allows the BFU (and heater H-9301) to be unloaded in order to meet the annual gasoline benzene specification. The resulting projected actual fired duty for BFU splitter reboiler H-9301 is less than the baseline actual fired duty of 105.4 MMBtu/hr. As such, for the sake of conservatism, the projected actual fired duty for heater H-9301 was set equal to the baseline actual value.

VI.3.4.1.5.2 Projected Actual NO_X, CO, $PM_{10/2.5}$, SO_2, and VOC Emissions

The projected actual NO_X, CO, $PM_{10/2.5}$, SO_2, and VOC emissions for heater H-9301 were set equal to the baseline actual values. The following table presents the parameters and emissions for heater H-9301.

Heater H-9301 Parameters and Emissions

EU ID	Baseline Actual Firing Rate (1)	Projected Actual Firing Rate	Pollutant	Baseline Actual Emissions(1)	Projected Actual Emissions	
	MMBtu/hr	MMBtu/hr		TPY	lb/hr	TPY
H-9301	105.4	105.4	CO	18.5	4.2	18.5
			PM_{10}	3.3	0.8	3.3
			NO_X	10.7	2.4	10.7
			SO_2	1.6	0.4	1.6
			VOC	2.2	0.5	2.2
			GHG	48,748	11,130	48,748

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.1.6 No. 3 Hydrotreater Desulfurizer Furnace H-6012 and No. 3 Catalytic Reforming Unit Main Furnace H-6007 and Reheat Furnace H-6013

VI.3.4.1.6.1 Projected Actual Fired Duty

As a result of the C5/C6 Molecule Management and No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement items (see Subsections V.1.6 and V.1.17, respectively), the projected actual fired duties for No. 3 Hydrotreater desulfurizer furnace H-6012, No. 3 Catalytic Reforming Unit main furnace H-6007, and No. 3 Catalytic Reforming Unit reheat furnace H-6013 are estimated to be less than the baseline actual fired duties of 22.9 MMBtu/hr, 120.4 MMBtu/hr, and 52.2 MMBtu/hr for heaters H-6012, H-6007, and H-6013, respectively. As such, for the sake of conservatism, the projected actual fired duties for heaters H-6012, H-6007, and H-6013 were set equal to the baseline actual values.

VI.3.4.1.6.2 Projected Actual NO_X, CO, SO_2, $PM_{10/2.5}$, and VOC Emissions

The projected actual NO_X, CO, SO_2, $PM_{10/2.5}$, and VOC emissions for heaters H-6007, H-6012, and H-6013 were estimated by multiplying the baseline actual emissions (TPY) by the ratio of the projected actual fired duties divided by the baseline actual fired duties. The following table presents the parameters and emissions for heaters H-6012, H-6007, and H-6013.

Heater H-6012, H-6007, and H-6013 Parameters and Emissions

EU ID	Baseline Actual Firing Rate (1)	Projected Actual Firing Rate	Pollutant	Baseline Actual Emissions(1)	Projected Actual Emissions	
	MMBtu/hr	MMBtu/hr		TPY	lb/hr	TPY
H-6012	22.9	22.9	CO	4.0	0.9	4.0
			PM_{10}	0.7	0.2	0.7
			NO_X	9.5	2.2	9.5
			SO_2	0.1	<0.1	0.1
			VOC	0.5	0.1	0.5
			GHG	11,171	2,550	11,171
H-6007	120.4	120.4	CO	0.1	<0.1	0.1
			PM_{10}	3.8	0.9	3.8
			NO_X	19.3	4.4	19.3
			SO_2	0.6	0.1	0.6
			VOC	2.8	0.6	2.8
			GHG	56,743	12,955	56,743
H-6013	52.2	52.2	CO	9.1	2.1	9.1
			PM_{10}	1.6	0.4	1.6
			NO_X	10.8	2.5	10.8
			SO_2	0.3	0.1	0.3
			VOC	1.2	0.3	1.2
			GHG	26,318	6,009	26,318

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.1.7 No. 4 Fluidized Catalytic Cracking Unit Preheat Furnace H-6151

VI.3.4.1.7.1 Projected Actual Fired Duty

As a result of the No. 4 FCCU Yield Improvements and Reliability, the No. 2 CTU Crude vs. Heating Oil Distillate and Kerosene vs. Raw Crude heat exchanger replacements, and the No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement items (see Sections IV.1.2, IV.1.7, and IV.1.17, respectively) the projected actual fired duty for No. 4 FCCU preheat furnace H-6151 is estimated to be less than the baseline actual fired duty of 44.1 MMBtu/hr. As such, for the sake of conservatism, the projected actual fired duty for heater H-6151 was set equal to the baseline actual values.

VI.3.4.1.7.2 Projected Actual NO_X, CO, $PM_{10/2.5}$, SO_2, and VOC Emissions

The projected actual NO_X, CO, $PM_{10/2.5}$, SO_2, and VOC emissions for heater H-6151 were set equal to the baseline actual emissions. The following table presents the parameters and emissions for heater H-6151.

Heater H-6151 Parameters and Emissions

EU ID	Baseline Actual Firing Rate (1)	Projected Actual Firing Rate	Pollutant	Baseline Actual Emissions(1)	Projected Actual Emissions	
	MMBtu/hr	MMBtu/hr		TPY	lb/hr	TPY
H-6151	44.1	44.1	CO	7.7	1.8	7.7
			PM_{10}	1.5	0.3	1.5
			NO_X	19.2	4.4	19.2
			SO_2	0.3	0.1	0.3
			VOC	1.1	0.3	1.1
			GHG	21,712	4,957	21,712

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.1.8 No. 5 Hydrotreater Reactor Charge Heater H-0023

VI.3.4.1.8.1 Projected Actual Fired Duty

The No. 5 Gas Oil Hydrotreater Reactor Replacement, No. 2 CTU Desalter Booster Pump P-6304 Impeller Replacement, No. 1 CTU Utilization Project, and South Tank Farm Expansion items (see Subsections V.1.5, V.1.17, V.1.23, V.2, respectively) will, among other things, increase the barrels per calendar day (not stream day) feed rate to the unit and correspondingly increase the projected actual fired duty for reactor charge heater H-0023 to 23.6 MMBtu/hr.

VI.3.4.1.8.2 Projected Actual NO_X, SO_2, $PM_{10/2.5}$, and VOC Emissions

The projected actual NO_X, SO_2, $PM_{10/2.5}$, and VOC emissions for heater H-0023 were estimated by multiplying the baseline actual emissions (TPY) by the ratio of the projected actual fired duty divided by the baseline actual fired duty.

VI.3.4.1.8.3 Projected Actual CO Emissions

The projected actual CO emissions for heater H-0023 were estimated by multiplying the projected actual fired duty by an assumed emission factor of 0.04 lb/MMBtu. The following table presents the parameters and emissions for heater H-0023.

Heater H-0023 Parameters and Emissions

EU ID	Baseline Actual Firing Rate (1)	Projected Actual Firing Rate	Pollutant	Baseline Actual Emissions(1)	Projected Actual Emissions	
	MMBtu/hr	MMBtu/hr		TPY	lb/hr	TPY
H-0023	21.3	23.6	CO	3.7	0.9	4.1
			PM_{10}	0.7	0.2	0.8
			NO_X	8.6	2.2	9.5
			SO_2	0.2	0.1	0.2
			VOC	0.5	0.1	0.6
			GHG	11,037	2,798	12,257

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.1.9 No. 2 Hydrotreater Desulfurizer Furnace H-0046

VI.3.4.1.9.1 Projected Actual Fired Duty

As a result of the Coker Unit Furnace Uptime Improvements, and On-Line Spalling, No. 1 CTU Utilization Project, and South Tank Farm Expansion items (see Subsections V.1.19, V.1.23, and V.2, respectively), the projected actual fired duty for the No. 2 Hydrotreater desulfurizer furnace H-0046 is estimated to be less than the baseline actual fired duty of 33.8 MMBtu/hr. As such, for the sake of conservatism, the projected actual fired duty for heater H-0046 was set equal to the baseline actual values.

VI.3.4.1.9.2 Projected Actual NO_X, CO, $PM_{10/2.5}$, SO_2, and VOC Emissions

The projected actual NO_X, CO, $PM_{10/2.5}$, SO_2, and VOC emissions for heater H-0046 were set equal to the baseline actual emissions. The following table presents the parameters and emissions for heater H-0046.

Heater H-0046 Parameters and Emissions

EU ID	Baseline Actual Firing Rate (1)	Projected Actual Firing Rate	Pollutant	Baseline Actual Emissions(1)	Projected Actual Emissions	
	MMBtu/hr	MMBtu/hr		TPY	lb/hr	TPY
H-0046	33.8	33.8	CO	5.9	1.3	5.9
			PM_{10}	1.1	0.3	1.1
			NO_X	14.1	3.2	14.1
			SO_2	0.3	0.1	0.3
			VOC	0.8	0.2	0.8
			GHG	11,274	2,574	11,274

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.1.10 No. 2 Catalytic Reforming Unit Reformer Furnace H-0048

VI.3.4.1.10.1 Projected Actual Fired Duty

As the result of the Coker Unit Furnace Uptime Improvements and On-Line Spalling, No. 1 CTU Utilization Project, and South Tank Farm Expansion items (see Subsections V.1.19, V.1.23, and V.2, respectively), the projected actual fired duty for No. 2 Catalytic Reforming Unit reformer furnace H-0048 is estimated to be less than the baseline actual fired duty of 216.6 MMBtu/hr. As such, for the sake of conservatism, the projected actual fired duty for heater H-0048 was set equal to the baseline actual values.

VI.3.4.1.10.2 Projected Actual NO_X, CO, $PM_{10/2.5}$, SO_2, and VOC Emissions

The projected actual NO_X, CO, VOC, and $PM_{10/2.5}$, SO_2, and VOC emissions for heater H-0048 were set equal to the baseline actual emissions. The following table presents the parameters and emissions for heater H-0048.

Heater H-0048 Parameters and Emissions

EU ID	Baseline Actual Firing Rate (1)	Projected Actual Firing Rate	Pollutant	Baseline Actual Emissions(1)	Projected Actual Emissions	
	MMBtu/hr	MMBtu/hr		TPY	lb/hr	TPY
H-0048	216.6	216.6	CO	1.5	0.3	1.5
			PM_{10}	7.0	1.6	7.0
			NO_X	31.7	7.2	31.7
			SO_2	2.1	0.5	2.1
			VOC	5.1	1.2	5.1
			GHG	72,747	16,609	72,747

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.1.11 No. 6 Hydrotreater Reactor Charge Heater H-7501

VI.3.4.1.11.1 Projected Actual Fired Duty

The No. 2 CTU Crude vs. Heating Oil Distillate and Kerosene vs. Raw Crude heat exchanger replacements, No. 1 CTU Utilization Project, and South Tank Farm Expansion items (see Subsections V.1.7, V.1.23, and V.2, respectively) will, among other things, increase production of diesel oil feed to the No. 6 Hydrotreater. The projected actual fired duty for No. 6 Hydrotreater Reactor Charge Heater H-7501 is less than the baseline actual fired duty of 23.6 MMBtu/hr. As such, for the sake of conservatism, the projected actual fired duty for heater H-7501 was set equal to the baseline actual values.

VI.3.4.1.11.2 Projected Actual NO_X, CO, $PM_{10/2.5}$, SO_2, and VOC Emissions

The projected actual NO_X, CO, VOC, $PM_{10/2.5}$, SO_2, and VOC emissions for heater H-7501 were set equal to the baseline actual emissions. The following table presents the parameters and emissions for heater H-7501.

Heater H-7501 Parameters and Emissions

EU ID	Baseline Actual Firing Rate (1)	Projected Actual Firing Rate	Pollutant	Baseline Actual Emissions(1)	Projected Actual Emissions	
	MMBtu/hr	MMBtu/hr		TPY	lb/hr	TPY
H-7501	23.6	23.6	CO	4.1	0.9	4.1
			PM_{10}	0.8	0.2	0.8
			NO_X	5.1	1.2	5.1
			SO_2	0.2	<0.1	0.2
			VOC	0.6	0.1	0.6
			GHG	5,349	1,221	5,349

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.1.12 No. 5 Fluidized Catalytic Cracking Unit Preheat Furnace H-5002

VI.3.4.1.12.1 Projected Actual Fired Duty

The Coker Unit Furnace Uptime Improvements and On-Line Spalling, No. 1 CTU Utilization Project, and South Tank Farm Expansion items (see Subsection V.1.19, V.1.23, and V.2, respectively) will, among other things, result in an increase in the gas oil feed in the No. 5 FCCU and a corresponding projected actual fired duty for preheat furnace H-5002 to 93.0 MMBtu/hr.

VI.3.4.1.12.2 Projected Actual NO_X, CO, $PM_{10/2.5}$, SO_2, and VOC Emissions

The projected actual NO_X, CO, $PM_{10/2.5}$, SO_2, and VOC emissions for heater H-5002 were estimated by multiplying the baseline actual emissions (TPY) by the ratio of the projected actual fired duty divided by the baseline actual fired duty.

The following table presents the parameters and emissions for heater H-5002.

Heater H-5002 Parameters and Emissions

EU ID	Baseline Actual Firing Rate (1)	Projected Actual Firing Rate	Pollutant	Baseline Actual Emissions(1)	Projected Actual Emissions	
	MMBtu/hr	MMBtu/hr		TPY	lb/hr	TPY
H-5002	88.9	93.0	CO	0.4	0.1	0.4
			PM_{10}	3.0	0.7	3.1
			NO_X	9.5	2.3	9.9
			SO_2	0.2	<0.1	0.2
			VOC	2.2	0.5	2.3
			GHG	60,404	14,326	62,749

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.1.13 No. 7 Coker Furnaces H-0028 and H-0029

VI.3.4.1.13.1 Projected Actual Fired Duty

As a result of the Coker Unit Furnace Uptime Improvements and On-Line Spalling, No. 1 CTU Utilization Project, and South Tank Farm Expansion items (see Subsections V.1.19, V.1.23, and

V.2, respectively), the projected actual fired duty for Coker furnace H-0028 is estimated to increase the fired duty to98.0 MMBtu/hr.

The projected actual fired duty for Coker furnace H-0029 was estimated to be less than the baseline actual fired duty of 54.4 MMBtu/hr. As such, for the sake of conservatism, the projected actual fired duty for heater H-9901 was set equal to the baseline actual value.

VI.3.4.1.13.2 Projected Actual NO_X, CO, $PM_{10/2.5}$, SO_2, and VOC Emissions

The projected actual NO_X, CO, $PM_{10/2.5}$, SO_2, and VOC emissions for furnace H-0028 were estimated by multiplying the baseline actual emissions (TPY) by the ratio of the projected actual fired duty divided by the baseline actual fired duty.

Heaters H-0028 and H-0029 Parameters and Emissions

EU ID	Baseline Actual Firing Rate (1)	Projected Actual Firing Rate	Pollutant	Baseline Actual Emissions(1)	Projected Actual Emissions	
	MMBtu/hr	MMBtu/hr		TPY	lb/hr	TPY
H-0028	94.8	98.0	CO	16.6	3.9	17.2
			PM_{10}	2.9	0.7	3.0
			NO_X	35.5	8.4	36.7
			SO_2	0.8	0.2	0.8
			VOC	2.1	0.5	2.2
			GHG	57,534	13,375	58,583
H-0029	45.4	45.4	CO	7.9	1.8	7.9
			PM_{10}	1.4	0.3	1.4
			NO_X	16.5	3.8	16.5
			SO_2	0.4	0.1	0.4
			VOC	1.0	0.2	1.0
			GHG	29,399	6,712	29,399

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.1.14 Boilers B-0008, B-0009, B-0010, and B-0022

Steam consumption increases required by the No. 4 FCCU Yields Improvements and Reliability, the HF Alkylation Unit Expansion, the C5/C6 Molecule Management, the Coker Unit Furnace Uptime Improvements and On-Line Spalling, the Olefin Recovery from FCC Gasoline, and South Tank Farm Expansion items (see Subsections V.1.2, V.1.3, V.1.6, V.1.19, V.1.24, and V.2, respectively) will be partially offset by an increase in steam production relative to current operation from the replacement of fuel gas-supplemented No. 5 FCCU waste heat boiler B-5004, which was required to be permanently removed from service on or before December 31, 2022, and not be returned to service, with a shell-and-tube waste heat exchanger. Permit No. 2012-702-C (M-11) stated that a remaining steam consumption increase (14,042 lb/hr) would be produced by a combination of the Ponca City Refinery fuel gas fired boilers (B-0008, B-0009, B-0010, and B-0022) and will require an increased fired duty rate of 20.8 MMBtu/hr. The worst-case increase for each pollutant was previously used for the Total Emissions Accounting (see Section VI.5). As a result of this permit modification, no additional steam consumption is expected. Therefore, for

the sake of conservatism, the projected actual fired duty for Boilers B-0008, B-0009/0010, and B-0022 were set equal to the baseline actual value.

Steam Boiler Parameters and Emissions

EU ID	Baseline Actual Firing Rate [1]	Projected Actual Firing Rate[2][3]	Pollutant	Baseline Actual Emissions[1]	Projected Actual Emissions	
	MMBtu/hr	MMBtu/hr		TPY	lb/hr	TPY
B-0008	332.5	332.5	CO	2.8	0.6	2.8
			PM_{10}	10.6	2.4	10.6
			NO_X	37.8	8.6	37.8
			SO_2	5.3	1.2	5.3
			VOC	0.9	0.2	0.9
			GHG	148,388	34,004	148,396
B-0009 / 0010[4]	427.8	427.8	CO	0.9	0.2	0.9
			PM_{10}	13.9	3.2	13.9
			NO_X	50.7	11.6	50.7
			SO_2	7.1	1.6	7.1
			VOC	1.5	0.3	1.5
			GHG	197,357	45,188	197,924
B-0022	65.2	65.2	CO	5.7	1.3	5.7
			PM_{10}	2.1	0.5	2.1
			NO_X	5.7	1.3	5.7
			SO_2	0.1	0.0	0.1
			VOC	1.5	0.3	1.5
			GHG	33,976	7,882	34,522

1. Based on the baseline period of January 1, 2018, to December 31, 2019.
2. Assumes 100% of the 20.8 MMBtu/hr increase represented at each boiler.
3. Assumes 79% heat transfer efficiency.
4. B-0009 and B-0010 share a single stack; therefore, baseline and projected emissions are shown together.

VI.3.4.1.15 No. 1 Crude Topping Unit Heaters H-0001 and H-0016

No. 1 Crude Topping Unit (CTU) furnaces H-0001 and H-0016 are not impacted to have significant increases by the 2020-2022 LRP Project or the No. 2. CTU Desalter Booster Pump P-6304 Impeller Replacement modification.

VI.3.4.1.15.1 Projected Actual Fired Duty

The No. 1 CTU Utilization Project and South Tank Farm Expansion items (see Subsections V.1.23 and V.2) will, among other things, increase the barrels of crude oil processed in the unit during a calendar year and correspondingly increase the projected actual fired duty for crude heater H-0001 to 244.2 MMBtu/hr and vacuum heater H-0016 to 91.7 MMBtu/hr.

VI.3.4.1.15.2 Projected Actual NO_X, CO, $PM_{10/2.5}$, SO_2, and VOC Emissions

The projected actual NO_X, CO, $PM_{10/2.5}$, SO_2, and VOC emissions for heaters H-0001 and H-0016 were estimated by multiplying the baseline actual emissions (TPY) by the ratio of the projected

actual fired duty divided by the baseline actual fired duty. The following table presents the parameters and emissions for heaters H-0001 and H-0016.

Heaters H-0001 and H-0016 Parameters and Emissions

EU ID	Baseline Actual Firing Rate (1)	Projected Actual Firing Rate	Pollutant	Baseline Actual Emissions(1)	Projected Actual Emissions	
	MMBtu/hr	MMBtu/hr		TPY	lb/hr	TPY
H-0001	239.0	244.2	CO	0.8	0.2	0.8
			PM_{10}	4.8	1.1	4.9
			NO_X	47.6	11.1	48.6
			SO_2	3.9	0.9	4.0
			VOC	5.7	1.3	5.8
			GHG	110,241	25,723	112,668
H-0016	90.2	91.7	CO	0.7	0.2	0.7
			PM_{10}	2.6	0.6	2.6
			NO_X	11.1	2.6	11.3
			SO_2	1.3	0.3	1.3
			VOC	1.0	0.2	1.0
			GHG	37,185	8,637	37,832

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.1.16 No. 4 Hydrotreater Heater H-1001

No.4 Hydrotreater (HDT) furnace H-1001 is not impacted by the 2020-2022 LRP Project because all incremental diesel and kerosene resulting from the project will be sent to the No. 6 and No. 9 Diesel Hydrotreaters.

VI.3.4.1.17 Reserved

VI.3.4.2 Associated Emissions Units – Coke Drum and Coke Pad Operations

VOC, $PM_{10/2.5}$, and H_2S emissions were estimated for the various operations involved in removal of petroleum coke from the coke drums; specifically, emissions that occur during coke drum venting, coke cutting, coke drum water handling, and coke pad operations. The methodology for estimating the emissions associated with these operations was previously submitted to ODEQ[7]. The projected actual emissions resulting from coke drum operations are assumed to be equal to the average values for the unit during the time period of January 1, 2018, to December 31, 2019 multiplied by the ratio of the future actual unit feed rate, which is the baseline actual feed rate of the Coker heaters H-0028 and H-0029 plus 1,200 BPD (see Subsection V.1.19), 184 BPD (see Subsection V.1.23), and 115 BPD (see Subsection V.2), divided by the baseline actual unit feed rate for the two Coker heaters. The 184 BPD is based on the volume of incremental resid oil (i.e., Coker unit feed) estimated to be recovered from the 1,245 BPD of crude oil discussed in Subsection V.1.23.

[7] "Application for Renewal of Title V Operating Permit No. 98-104-TV (M-10) – Update II – Phillips 66 Company (formerly ConocoPhillips Company) – Ponca City Refinery – Ponca City, Oklahoma" from Mr. Dave Gamble, Phillips 66 Company, to Mr. Phillip Fielder, Oklahoma Department of Environmental Quality dated December 20, 2012.

Projected actual $PM_{2.5}$ emissions resulting from coke pad operations are assumed to be equal to 1.0 TPY (the average coke pad $PM_{2.5}$ emissions for the baseline period of January 1, 2018, to December 31, 2019, was 0.2 TPY). The following tables summarize the coke drum and coke pad operations emissions.

Coker Feed Rates

Baseline Period	Actual Feed Rate		Baseline Actual Feed Rate	Projected Actual Feed Rate[(1)]
	2018	2019		
	BPD	BPD	BPD	BPD
1/1/2018 to 12/31/2019[(2)]	22,482	20,842	21,662	23,161

1. Based on the baseline period of January 1, 2018, to December 31, 2019.
2. Baseline period corresponds to VOC and H_2S emissions.

Coke Drum and Coke Pad Emissions

Operation	Pollutant	Actual Emissions		Baseline Actual Emissions[(1)]	Projected Actual Emissions
		2018	2019		
		TPY	TPY	TPY	TPY
Coke Drum Handling, Coke Cutting, and Water Handling	VOC	16.3	12.5	14.4	15.4
	$PM_{10/2.5}$	2.5	2.3	2.4	2.6
	H_2S	3.0	2.7	2.9	3.0
	GHG	20	30	25	27
Coke Pad	$PM_{10/2.5}$	0.2	0.2	0.2	1.0
Totals	**VOC**	**-**	**-**	**14.4**	**15.4**
	$PM_{10/2.5}$	**-**	**-**	**2.6**	**3.6**
	H_2S	**-**	**-**	**2.9**	**3.1**
	GHG	**-**	**-**	**25**	**27**

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.3 Associated Emissions Units – Storage Tanks

The 2020-2022 LRP Project is projected to result in the following changes in alkylate, gasoline, and diesel oil stream yields.

Storage Yield Stream Changes

2020-2022 LRP Project Element	Alkylate Increase	Gasoline Increase	Diesel Oil Increase
	BPD	BPD	BPD
No. 4 FCCU Yield Improvements and Reliability	1,706	121	-846
HF Alkylation Unit Expansion	538	-417	0
Coker Unit Furnace Uptime Improvements and Spalling	34	260	532
No. 5 Hydrotreater Reactor Replacement	74	289	29
C5/C6 Molecule Management	0	1,503	-440

2020-2022 LRP Project Element	Alkylate Increase	Gasoline Increase	Diesel Oil Increase
	BPD	BPD	BPD
No. 2 CTU vs. Heating Oil Distillate Heat Exchanger Replacement	20	103	120
Improved No. 8 Hydrotreater Reliability	0	197	0
Segregate Diesel Rundown Streams	0	-460	460
Totals	**2,372**	**1,596**	**-145**

The VOC emission increases resulting from changes in oil movements in storage tanks were estimated by adding the product stream flow rate changes listed above to the baseline period (2018-2019) throughputs for the following storage tanks:

Storage Tank	Product Stream
T-0125	Diesel Oil
T-0165	Alkylate
T-0166	Gasoline

Assuming that the total increases in individual product streams will pass through a single tank is believed to be the most conservative approach as opposed to spreading the product streams out through multiple tanks. The following table presents the parameters and emissions for tanks T-0125, T-0165, and T-0166.

Oil Movement Storage Tank Parameters and Emissions

Tank	T-0125	T-0165	T-0166
Material Stored	Diesel Oil	Alkylate	Gasoline
Maximum Reid Vapor Pressure, psi	0.022	6	12.978
Tank Capacity, physical gallons	3,684,661	3,405,021	4,060,647
Tank Capacity, working gallons	3,647,814	2,982,037	3,679,961
Tank Height, feet	50	40.25	48
Tank Diameter, feet	112	120	120
Tank Color	White	White	White
Storage Temperature, °F	60	80	60
Venting System	Atmospheric	Atmospheric	Atmospheric
Controls (Roof Type)	VFR	EFR	EFR
Standing Losses, TPY	0.3	3.3	13.6
Working Losses, TPY	1.6	0.1	0.2
Cleaning Emissions, TPY(1)	0.1	0.2	0.4
Total Emissions, TPY	2.0	3.6	14.2
Baseline Actual Emissions(2), TPY	**1.8**	**3.9**	**13.9**
Projected Actual Emissions, TPY	**1.9**	**3.9(3)**	**14.2**

1. Based on 13-year average (2008-2020).
2. Based on the baseline period of January 1, 2018, to December 31, 2019, unless otherwise noted.
3. Projected Actual Emissions were estimated to be less than the Baseline Actual Emissions. The projected actual emissions were set equal to the baseline actual emissions.

VI.3.4.4 Associated Emissions Units – Ponca City Pipeline Activities

The South Crude Tank Farm, Cherokee Pump Station, Ponca City Products Terminal, and the Ponca City Refinery are considered collocated and part of a single facility site for the purpose of emissions evaluation and regulatory applicability. Therefore, the South Crude Tank Farm, Cherokee Pump Station and loading rack operations are associated with the items included in Permit No. 2012-704-C (M-11) and this permit modification, specifically the No, 1 CTU Utilization Project item (see Subsection V.1.23).

The projected actual emissions resulting from the South Tank Farm, Cherokee Pump Station, and Ponca City Products Terminal were calculated by multiplying the baseline period crude throughput by the expected percent increase resulting from the 1,245 BPD crude rate from the No. 1 CTU Utilization Project (see Subsection and V.1.23).

South Tank Farm Operations

Calendar Year	SO_2	CO	NO_X	VOC	Crude Throughput
	TPY	TPY	TPY	TPY	BPD
2018	<0.1	2.0	1.0	117.9	220,690
2019	<0.1	<0.1	<0.1	115.5	213,205
Baseline Period (1)	<0.1	1.0	0.5	116.7	216,948
Projected Actual	0.1	1.0	0.5	117.4	218,193

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

Cherokee Pump Station Operations

Calendar Year	SO_2	CO	NO_X	VOC	Throughput
	TPY	TPY	TPY	TPY	BPD
2018	<0.1	<0.1	<0.1	0.5	3.3
2019	<0.1	<0.1	<0.1	0.4	3.5
Baseline Period (1)	<0.1	<0.1	<0.1	0.5	3.4
Projected Actual	<0.1	<0.1	<0.1	0.5	3.5

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

Ponca City Products Terminal Operations

Calendar Year	SO_2	CO	NO_X	VOC	Throughput
	TPY	TPY	TPY	TPY	BPD
2018	<0.1	<0.1	<0.1	12.2	11,806
2019	<0.1	<0.1	<0.1	12.6	12,829
Baseline Period (1)	<0.1	<0.1	<0.1	12.4	12,318
Projected Actual	<0.1	<0.1	<0.1	12.5	218,193

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.4.5 Associated Emissions Units – Wastewater Treatment System

The projected annual emissions resulting from the wastewater treatment system were calculated by multiplying the baseline period operation by the expected percent increase resulting from the 1,245 BPD crude rate from the No. 1 CTU Utilization Project (see Subsection V.1.23).

Wastewater Treatment System

Calendar Year	Wastewater Treatment System VOC Emissions	Crude Throughput
	TPY	BPD
2018	11.6	220,690
2019	12.0	213,205
Baseline Period(1)	11.8	216,948
Projected Actual	11.9	218,193

1. Based on the baseline period of January 1, 2018, to December 31, 2019.

VI.3.5 Auxiliary Equipment

The following is a summary of the rationale for the non-inclusion of various facility auxiliary equipment as associated emission units.

VI.3.5.1 Emergency and Startup Equipment

Emergency equipment such as instrument air back up portable air compressors are not included as associated emission units because none of the 2020-2022 LRP Project, the changes included in this permit modification, or the South Tank Farm Expansion Project are expected to increase the number or frequency of emergency situations during which such equipment would be put into service. Similarly, startup equipment such as the No. 5 FCCU regenerator air preheaters are not included as associated emission units because neither the 2020-2022 LRP project or the changes included in this permit modification are not expected to increase the number or frequency of unit startups during which such equipment would be put into service.

VI.3.5.2 Building Boilers

Building boilers are not included as associated emission units because their operation is not associated with the 2020-2022 LRP Project, the changes included in this permit modification, or the South Tank Farm Expansion Project.

VI.3.5.3 Catalytic Reformer Regeneration Vents

Emissions from CRU regeneration vents only occur during catalyst regenerations which are a function of unit severity (i.e., octane) and catalyst conditions (e.g., age) rather than throughput. The No. 2 and 3 CRUs essentially run at full capacity all of the time, so the frequency of catalyst regenerations is not expected to change as a result of the 2020-2022 LRP Project, the changes included in this permit modification, or the South Tank Farm Expansion Project.

VI.3.5.4 Flares

The items included in the 2020-2022 LRP Project, the changes included in this permit modification, and the South Tank Farm Expansion Project are not expected to result in an increase in malfunction events and subsequent releases at any of the Ponca City Refinery flares. During the past several years, the Ponca City Refinery has implemented a vigorous flare minimization program which, combined with the conditions, requirements, etc., of regulations including NSPS Subpart Ja, and MACT Subpart CC, has resulted in a significant decrease in malfunction events. As such, there are no projected emission increases from any of the Ponca City Refinery flares as a result of the 2020-2022 LRP Project, the changes included in this permit modification, or the South Tank Farm Expansion Project.

VI.3.5.5 Process Vents

Process vents would only be a concern if they were routed to the atmosphere or through a control device to the atmosphere. Any process vents (e.g., Butamer Merox foul air vent) are routed to a flare system where the gases are captured by the associated flare gas recovery unit (FGRU) and returned to one of the Ponca City Refinery fuel gas systems.

VI.3.5.6 Site Remediation Activities

Site remediation activities and their associated emissions are not dependent on refinery crude oil or process unit throughputs. As such, they are not associated sources for the 2020-2022 LRP Project or the changes included in this permit modification.

VI.3.5.7 Fugitive Sources

Emissions from existing fugitive sources (e.g., valves, flanges, pump seals, etc.) will not change as a result of increased refinery process unit throughputs. As such, they are not associated sources for the 2020-2022 LRP Project, the changes included in this permit modification, or the South Tank Farm Expansion Project.

VI.3.5.8 Cooling towers

Emissions from existing cooling towers will not change as a result of the increased refinery process unit throughputs as there will be no change in water circulation rates in the existing cooling towers. As such, they are not associated sources for the 2020-2022 LRP Project, the changes included in this permit modification, or the South Tank Farm Expansion Project.

VI.4 EMISSION DECREASES FROM THE PROJECTS

On August 1, 2019, EPA proposed a rule that would amend the New Source Review (NSR) applicability regulations to clarify that both emissions increases and decreases which are part of a single project may be considered in Step 1[8] of the NSR major modification applicability test. The agency had previously explained in a memorandum dated March 13, 2018[9], that it interprets the current NSR regulations as providing that emissions decreases as well as increases from a major modification are to be considered at Step 1 of the NSR applicability process. The final rule was published on November 24, 2020[10].

With the cancelation of the Saturated Gas Plant Compressor Replacement, project emissions decreases will no longer be taken into consideration.

VI.5 TOTAL EMISSIONS ACCOUNTING

The following table compares the project-related emission increases and decreases for all pollutants with PSD SERs to determine if further analysis is required.

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[8] The agency currently refers to Step 1 applicability procedures as "project emissions accounting" (previously known as "project netting") and step 2 as "contemporaneous netting."

[9] Letter from E. Scott Pruitt, to Regional Administrators, "Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program," March 13, 2018.

[10] 85 Fed. Reg. 74890-74909 (November 24, 2020).

Project-Related Emission Increases and Decreases for PSD Regulated Pollutants

Pollutant	Project Emission Increases[1]	Associated Emission Increases[2]	Project Emission Decreases	Total Emission Increases and Decreases	PSD Significant Emission Rates	PSD Netting?
	TPY	TPY	TPY	TPY	TPY	
CO	185.0	7.0	--	192.0	100	**Yes**
$PM_{10/2.5}$	1.6	3.7	--	5.3	10[3]	No
NO_X	23.6	14.5	--	38.1	40	No
SO_2	5.6	1.1	--	6.7	40	No
VOC	13.1	4.1	--	17.2	40	No
H_2S	<0.1	0.2	--	0.2	10	No
GHG	40,031	55,721	--	95,752	75,000	**Yes**

1. Actual-to-potential for new or modified emissions units, sources with permit limit changes, and fugitive sources (e.g., valves, flanges, etc.).
2. Actual-to-projected actual.
3. For purpose of this review, the SER for $PM_{2.5}$ (10 TPY) is used rather than the SER for PM_{10} (15 TPY).

VI.6 CONCLUSION

The projects in Permit No. 2012-704-C (M-11) and the changes included in this permit modification are subject to PSD review for each NSR regulated pollutant for which the sum of all project-related emissions increases and decreases results in a significant net emissions increase. PSD review is not required for $PM_{10/2.5}$, NO_X, SO_2, VOC, and H_2S because the project-related emissions increases and decreases do not exceed the PSD SER levels. However, the project related emissions increases for CO and GHG exceed the applicable PSD SER levels for those pollutants. Therefore, BACT analyses and an ambient air impacts analysis are required.

SECTION VII. BACT ANALYSIS

The requirement to conduct a BACT analysis is set forth in the PSD regulations under OAC 252:100-8-30 through 39. Per OAC 252:100-34, any major modification subject to PSD review must conduct an analysis to ensure the use of BACT for each new or physically modified emission unit for each pollutant that exceeds an applicable PSD significant emission rate (SER).

VII.1 BACT Methodology

Any major stationary source or major modification subject to PSD review must undergo an analysis to ensure the use of the best available control technology (BACT). The requirement ot conduct a BACT analysis is set forth in OAC 252:100-8-34(b). BACT is defined in OAC 252:100-8-31 as:

> *"…best available control technology means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major*

> *modification which the Director, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combination techniques for control of such pollutant…"*

A BACT analysis is required for each new or physically modified emission unit for each pollutant that exceeds an applicable PSD significant emission rate (SER). Since CO and GHG emissions from the proposed project exceed the applicable SERs, a BACT analysis is required to assess the necessary levels of control for this pollutant.

The following methodology for performing a top-down BACT analysis has been developed from the US EPA's 1990 Draft New Source Review Workshop Manual - BACT Guidance. The analysis utilizes five key steps to identify the most suited BACT option for the project. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically, environmentally, or economically infeasible for the unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

Step 1: Identify Available Control Technologies

Available control technologies or techniques are identified for each emission unit in question. The following methods are used to identify potential control technologies: 1) researching the Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database; 2) surveying regulatory agencies; 3) drawing from previous engineering experience; 4) surveying air pollution control equipment vendors; and 5) surveying available literature.

Step 2: Eliminate Technically Infeasible Options

After the identification of control options, an analysis is conducted to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that prohibit the implementation of the control technology.

Step 3: Rank Remaining Control Options by Control Effectiveness

Once technically infeasible options are removed from consideration, the remaining options are ranked based on their control effectiveness. If there is only one remaining option, or all of the remaining technologies could achieve equivalent control efficiencies, ranking based on control efficiency is not required.

Step 4: Evaluate and Eliminate Control Technologies Based on Energy, Environmental, and Economic Impacts

Beginning with the most efficient control option in the ranking, detailed economic, energy, and environmental impact evaluations are performed. If a control option is determined to be economically feasible without adverse energy or environmental impacts, it is not necessary to evaluate the remaining options with lower control efficiencies.

The economic evaluation centers on the cost effectiveness of the control option. Costs of installing and operating control technologies are estimated following the methodologies outlined in the EPA's OAQPS Control Cost Manual (CCM) and other industry resources. Cost effectiveness is expressed as dollars per ton of pollutant controlled. Objective analyses of energy and environmental impacts associated with each option are also conducted. Both beneficial and adverse impacts are discussed and quantified.

Step 5: Select BACT and Document the Selection as BACT

In the final step, one pollutant specific control option is proposed as BACT for each emission unit under review based on evaluations from the previous step. The resulting BACT standard is an emission limit unless technological or economic limitations of the measurement methodology would make the imposition of an emissions standard infeasible, in which case a work practice standard can be imposed.

Lastly, if a source is subject to an NSPS, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate less than or equal to the NSPS emission rate. In other words, the applicable NSPS limit represents the maximum allowable emission limit (or ceiling) for an emission source.

VII.2 BACT Analysis for Fluidized Catalytic Cracking Units – CO Emissions

CO emissions are a by-product of incomplete combustion, which can be caused by insufficient oxygen, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, tramp oil contamination, and load reduction.

The combustion of coke in an FCCU provides the heat needed for cracking reaction. High temperature operation, which is the base case of the No. 4 FCCU and the No. 5 FCCU, ensures efficient combustion and reduced CO emissions. It should be noted that during periods of startup, shutdown, and hot standby (S/S/HS), the FCCUs are not operating at peak capacity and efficiency, the exhaust concentration of CO can be evaluated even when CO emissions on a mass basis may be less than during normal operations.

A top-down BACT evaluation for CO emissions from the No. 4 FCCU and the No. 5 FCCU is presented in this section.

VII.2.1 Step 1 – Identify All Control Technologies

Potentially applicable emission control technologies were investigated using applicable regulations, technical literature, process knowledge and engineering experience, and the EPA's RBLC. A search of the RBLC database was conducted by the applicant on January 23, 2024, to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT for the category, Petroleum Refining Conversion processes (process Code 50.003 in the RBLC system). The search included all RBLC database entries except those that were currently under review on the date of the search. Complete search results are presented in the following table. Entries that exceeded the size of the table fields were truncated. Phillips 66 also included several limitations from other Phillips 66 refineries throughput the country which were not identified in the RBLC.

RBLCID	COMPANY NAME; FACILITY NAME	PERMIT #; ISSUANCE DATE	PROCESS NAME; THROUGHPUT	PROCESS_NOTES	CONTROL METHOD DESCRIPTION	EMISSION LIMIT(S)	POLLUTANT COMPLIANCE NOTES
AR-0089	LION OIL COMPANY; LION OIL COMPANY REFINERY, EL DORADO	868-AOP-R2; 01/03/2005	FLUIDIZED BED CATALYTIC CRACKING UNIT (FCCU);		USE OF FULL COMBUSTION	500 PPMVD@0%02 1 HOUR AVERAGE; 100 PPMVD@0%02 365 DAY ROLLING AVERAGE	
AR-0100	LION OIL COMPANY; LION OIL COMPANY	868-AOP-R5; 10/01/2007	#7 FCCU CATALYST REGENERATOR, SN-809; 9.34 MMBBL CHARGE STOCK		HIGH TEMPERATURE REGENERATION	100 PPMDV 365 DAY AVERAGE, CEMS; 500 PPMDV 1-HR AVERAGE, CEMS	
AZ-0001	PROVIDENT ENERGY CO.; PROVIDENT ENERGY CO.	NONE; 03/03/1980	FCC UNIT &; CATALYIST REGEN.	NO NEW EMISSIONS SOURCES ARE INCLUDED IN THE SCOPE OF THE PROJECT FOR THE FCCU EXPANSION. HOWEVER, EMISSIONS INCREASES WILL RESULT FROM THE INCREASED THROUGHPUT. SN-809 IS THE	CO BOILER		
CA-1118	BP WEST COAST PRODUCTS; BP WEST COAST PRODUCTS	397357; 05/01/2002	CATALYST REGENERATION-FLUIDIZED CATALYST		SCR	500 PPMVD@0%O2 1 H AV	
IL-0103	CONOCOPHILLIPS; CONOCOPHILLIPS WOOD RIVER REFINERY	06050052; 08/05/2008	MODIFIED FLUIDIZED CATALYTIC CRACKING UNITS 1 &; 2;	EQUIP:, MFR:, TYPE:, MODEL:, FUNC EQUIP: SEE NOTE, FUEL_TYPE:, SCHED: CONTINUOUS, H/D:24,D/W:7,W/Y:52,NOTES: FUNCTION: FCCU CONVERTS HEAVY REF PROD TO LIGHTER PROD THAT	CO FUELED HEATER OR OTHER COMBUSTION DEVICE.	100 PPMV, AT 0% O2 365-DAY ROLLING AVERAGE; 500 PPMV, AT 0% O2 HOURLY AVERAGE	
IL-0103	CONOCOPHILLIPS; CONOCOPHILLIPS WOOD RIVER REFINERY	06050052; 08/05/2008	FLUIDIZED CATALYTIC CRACKING UNIT 3;	PARTIAL COMBUSTION UNITS.	PROCESS DESIGN	150 PPMV, AT 0% O2 356-DAY ROLLING AVERAGE; 500 PPMV, AT 0% O2 HOURLY AVERAGE	
KS-0041	HOLLYFRONTIER EL DORADO REFINING LLC; HOLLYFRONTIER EL DORADO REFINERY	CSD00080 V1.0; 10/30/2019	Fluid Catalytic Cracking Unit; 48000 BPD	RESTART OF UNIT AFTER EXTENDED OUTAGE. UNIT IS OF FULL COMBUSTION DESIGN.	Full Burn Combustion Operation	100 PPMVD 365-DAY ROLLING AVERAGE; 500 PPMVD 1-HOUR BLOCK AVERAGE	Both Emission Limits should be corrected to 0% O2.
KS-0042	COFFEYVILLE RESOURCES REFINING & MARKETING, LLC; COFFEYVILLE REFINERY	CSD00079 V1.0; 10/31/2019	Fluid Catalytic Cracking Unit; 39000 BPD	BACT Emission Limits for this unit were proposed based on issued Construction Permit C-9191 (based on Consent Decree, Civil Action Case No. 09-CV-1032-WEB-KMH) and were accepted as BACT by the KDHE.	Full burn combustion (use of high temperature and excess oxygen)	500 PPMV 1 HOUR	
LA-0022	TENNECO; TENNECO	PSD-LA-199; 12/23/1981	REGENERATOR, FCCU; 42000 BPSD		COMPLIANCE W/ NSPS	212.8 LB/H	
LA-0022.A	TENNECO OIL CO.; TENNECO OIL CO.	PSD-LA-199(M-1); 11/21/1984	REGENERATOR, FCCU; 42000 BPSD		PROMOTER CATALYST FOR CI	198.88 LB/H	
LA-0029	VENTECH REFIN.; VENTECH REFIN.	NONE; 02/13/1980	CATALYTIC REGEN; 0		FLOT REGEN	104.7 LB/H	
LA-0032	GOOD HOPE REFIN., INC.; GOOD HOPE REFIN., INC.	NONE; 05/08/1981	REGENERATOR, FCCU; 82000 BBL/D		COMBUSTION CONTROL	138.6 LB/H	
LA-0078	MURPHY OIL U.S.A., INC.; MURPHY OIL U.S.A., INC.	PSD-LA-566; 06/14/1991	FCCU (FLUID CATALYTIC CRACKING UNIT); 28000 BBL/D		HIGH TEMP REGENERATOR AT >1300 DEGREES F	7.6 LB/1000 LB COKE; 197.8 LB/H	
LA-0085	TRANSAMERICAN REFINING CORPORATION (TARC); TRANSAMERICAN REFINING CORPORATION (TARC)	PSD-LA-571; 01/15/1993	CATALYTIC CRACKING FCCU REGENERATOR; 110000 BBL/D		CO BOILER		CO EMISSIONS FROM THE FCCU REGENERATOR (PROCESS 1) ARE NEGLIGIBLE AFTER LEAVING THE CONTROL DEVICE
LA-0085	TRANSAMERICAN REFINING CORPORATION (TARC); TRANSAMERICAN REFINING CORPORATION (TARC)	PSD-LA-571; 01/15/1993	REGENERATOR, FCCU (NO.1); 29000 BBL/D		CO BOILER	0 SEE NOTE 4 In Facility Notes	
LA-0090	TRANSAMERICAN REFINING CORPORATION; TRANSAMERICAN REFINING CORPORATION	PSD-LA-571 (M-1); 02/10/1995	REGENERATOR, FCCU; 75000 BBL/D		CO BOILER OR HIGH TEMP REGENERATION	0.01 NEGLIGIBLE	
LA-0211	MARATHON PETROLEUM CO LLC; GARYVILLE REFINERY	PSD-LA-719; 12/27/2006	FCCU REGENERATOR VENT (86-74);		FULL BURN OPERATION; MONITOR DAILY COKE BURN-OFF RATE	481.76 MAX LB/H	
LA-0213	VALERO REFINING - NEW ORLEANS, LLC; ST. CHARLES REFINERY	PSD-LA-619(M5); 11/17/2009	FCCU REGENERATOR (16-77);		FULL BURN DESIGN	696.8 LB/H; 95 T/YR	
LA-0222	CHALMETTE REFINING, LLC; CHALMETTE REFINERY	PSD-LA-199(M-8); 09/15/2009	FLUIDIZED CATALYTIC CRACKING UNIT (FCCU);	130,000 BBLS/DAY	FULL BURN MODE OPERATION AND GOOD COMBUSTION PRACTICES	732.8 T/YR ANNUAL MAXIMUM; 500 PPMV @ 0% O2 1-HOUR AVERAGE*	*HOURLY MAXIMUM = 300.25 LB/H
LA-0238	CONOCOPHILLIPS COMPANY; ALLIANCE REFINERY	PSD-LA-75(M3); 07/10/2009	FCCU REGEN VENT - SU/SD OPERATIONS; 89000 BBL/D			16674.18 LB/H HOURLY MAXIMUM	
MI-0378	MARATHON PETROLEUM COMPANY; MARATHON PETROLEUM DETROIT REFINERY	28-02A; 01/05/2006	FCCU CATALYST REGENERATION; 105000 BBL/D		GOOD COMBUSTION PRACTICES.	573 T/YR ANNUAL; 500 PPMV HOURLY	NO COST EFFECTIVENESS WAS CONSIDERED. OXIDATION IS THE ONLY FEASIBLE CONTROL TECHNOLOGY FOR CO.
MS-0086	CHEVRON PRODUCTS COMPANY; CHEVRON PRODUCTS COMPANY, PASCAGOULA	1280-00058; 05/08/2007	CONTINUOUS CATALYST REGENERATOR VENT;	NOX REDUCING CATALYST ADDITIVE PROJECT. DURING THE CATALYTIC HYDROCARBON CRACKING PROCESS, CARBON DEPOSITS FORM ON THE SURFACE OF THE CATALYST. IN ORDER TO REUSE THE	FULL-BURN COMBUSTION	0.97 LB/H 3-HR ROLLING AVERAGE; 4.24 T/YR 12-MONTH ROLLING AVERAGE	
NJ-0063	CONOCO PHILLIPS COMPANY; BAYWAY REFINERY	PCP 030001; 11/12/2004	PETROLEUM REFINING USING FLUID CATALYTIC CRACKING UNIT	WILL HAVE A GAS-SOLID ADSORPTION SYSTEM FOR HCL REMOVAL AND RESIDUAL CONTAMINANT REMOVAL SYSTEM FOR DIOXIN REMOVAL.	TWO CO -BOILERS	334.7 LB/H; 381.4 T/YR	COMPLIANCE VERIFIED BY CEMS AND STACK TESTING.
NJ-0064	AMERADA HESS CORPORATION; HESS PORT READING REFINERY	PCP 050001; 03/01/2005	PETROLEUM REFINING USING CATALYTIC CRACKING UNIT		FULL BURN MODE IN REGENERATOR.	160 LB/H; 480 T/YR	COMPLIANCE BY CEMS AND STACK TESTING.
NJ-0065	VALERO REFINING COMPANY NJ; VALERO	PCP 020001; 09/24/2002	FLUID CATALYTIC CRACKING UNIT; 75000 BBL/D			34.4 LB/H; 150.5 T/YR	
OH-0308	SUNOCO, INC.; SUN COMPANY, INC., TOLEDO REFINERY	04-01447; 02/23/2009	FLUIDIZED CATALYTIC CRACKING UNIT; 84200 LB/H COKE		TWO BOILERS BURNING, IN PART, THE FCCU WASTE GASES	180 PPMVD@ 0% O2 AS ROLLING 365-DAY AVERAGE AT 0% O2; 1087.28 T/YR ROLLING 365-	THESE LIMITS ARE SHARED WITH THE TWO BOILERS CONTROLLING CO, I.E., THE LB/H AND T/YR LIMITS ARE FOR THE

RBLCID	COMPANY NAME; FACILITY NAME	PERMIT #; ISSUANCE DATE	PROCESS NAME; THROUGHPUT	PROCESS_NOTES	CONTROL METHOD DESCRIPTION	EMISSION LIMIT(S)	POLLUTANT COMPLIANCE NOTES
OK-0089	TPI PETROLEUM INC.; TPI PETROLEUM INC., VALERO ARDMORE REFINERY	98-172-C (M-12) (PSD); 06/09/2003	REGENERATOR &; THERMAL OXIDATION SYSTEM, FCCU NO. 1;	FLUIDIZED CATALYTIC CRACKING UNIT (FCCU) WITH CAPACITY OF 100,000 BARRELS/DAY; W/ CO CONTROLLED BY TWO BOILERS (WHICH SHARE EMISSIONS LIMITS WITH THE FCCU); AN SCR SYSTEM	CO BOILER AND INCINERATOR	49.9 T/YR 12-mo rolling avg	Emission limits in t/yr only.
OK-0089	TPI PETROLEUM INC.; TPI PETROLEUM INC., VALERO ARDMORE REFINERY	98-172-C (M-12) (PSD); 06/09/2003	REGENERATOR, FCCU NO. 2;		HIGH TEMPERATURE REGENERATION	4.2 T/YR 12 mo rolling avg	emission limit in t/yr only
OK-0092	TPI PETROLEUM; VALERO ARDMORE REFINERY	98-172-C PSD; 01/13/2003	FCCU REGENERATOR NO. 2;		HIGH TEMPERATURE REGENERATION	4.2 T/YR see note	Permitted limit is in t/yr. Stack test results show a maximum of .04 ppmv from this unit.
OK-0092	TPI PETROLEUM; VALERO ARDMORE REFINERY	98-172-C PSD; 01/13/2003	FCCU REGENERATOR NO. 1;	THE FCCU REGENERATOR OPERATES IN TWO STAGES; THE FIRST REGENERATOR OPERATES IN AN OXYGEN DEFICIENT, PARTIAL BURN	CO BOILER AND INCINERATOR	49.9 T/YR see note	Permitted limit is in T/YR. Vendor's estimated emission rate is 50 ppmv
OK-0102	CONOCOPHILLIPS; PONCA CITY REFINERY	2003-336-C PSD; 08/18/2004	FCCU, (2);	THE FCCU REGENERATOR OPERATES IN TWO STAGES; THE FIRST REGENERATOR OPERATES IN AN OXYGEN DEFICIENT, PARTIAL BURN	NO. 4 FCCU-CO COMBUSTION PROMOTER, NO. 5 FCCU-CO BOILER(THERMAL	150 PPMVD @ 0% O2	
OK-0116	VALERO REFINING CO; VALERO ARDMORE REFINERY	98-172-C M-19 PSD; 02/08/2007	FCCU NO. 1 REGENERATOR AND CO BOILER/INCINERATOR	FCCU units 4 & 5, Unit 5 future max rate: 48,000 bbl/day	THERMAL OXIDATION	175 PPMVD @0% O2	
OK-0116	VALERO REFINING CO; VALERO ARDMORE REFINERY	98-172-C M-19 PSD; 02/08/2007	FCCU NO. 2 REGENERATOR;		HIGH TEMPERATURE REGENERATION	50 PPMVD @0% O2	
OK-0182	HOLLYFRONTIER TULSA REFINING EAST; TULSA REFINERY EAST	2017-1908-C(M-2)PSD; 02/10/2020	Fluid Catalytic Cracking Unit; 24000 Barrels per Day			500 PPM 1-HR @ 0% O2	
PA-0238	SUNOCO INC.; SUNOCO, INC.	23-0001M; 07/03/2001	FLUID CATALYTIC CRACKING UNIT;			2.2 LB/H	
PA-0250	SUNOCO, INC. (R&M); SUNOCO, INC. (R&M)	04322; 02/28/2006	1232 FCCU; 100000 Barrels/Day		EXISTING CO BOILER	100 PPMDV @ 0% O2 365-DAY ROLAVG; 500 PPMDV @ 0% O2 1-HOUR AVG	
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.; WILLIAMS REFINING & MARKETING, L.L.C.	0101-08PC AND 1010-05PCR; 04/03/2002	FLUIDIZED CATALYTIC CRACKING UNIT;	LIMITED TO 90,000 BPD ON A ROLLING 365-DAY AVG. OR 100,000 BPD FOR A SINGLE DAY. EXISTING CO BOILER, REPLACING ESP WITH SCR & WET GAS SCRUBBER		50 PPM annual avg; 100 PPM 24 hr avg	
TX-0029	LONGVIEW REFIN.; LONGVIEW REFIN.	PSD-TX-364; 05/08/1981	REGENERATOR, FCC; 15000 BBL/D		HIGH TEMP REGENERATION	79.5 LB/H	
TX-0034	DIAMOND SHAMROCK CORP.; DIAMOND SHAMROCK CORP.	TX-346; 09/04/1981	REGENERATOR STACK, FCCU, 2; 45000 BBL/D		HIGH TEMP REGENERATION	195 LB/H	
TX-0039	SIGMORE REFIN. CO.; SIGMORE REFIN. CO.	NONE; 12/10/1980	REGENERATOR, FCCU; 40 MBPSD		HIGH TEMP REGENERATION	90.12 LB/H	
TX-0060	NEDERLAND PROCESSING CO.; NEDERLAND PROCESSING CO.	TX-262; 10/31/1980	REGENERATOR, FCCU; 0		COMBUSTION CONTROL	73.5 LB/H; 500 PPMV, LESS THAN	
TX-0061	UNI OIL; UNI OIL	NONE; 03/12/1980	FCC UNIT; 17000 BBL/D		HIGH TEMP REGENERATION	89.0999 LB/H	
TX-0066	COASTAL STATES PETROLEUM; COASTAL STATES PETROLEUM	TX-243; 10/14/1980	REGENERATOR, FCCU; 0		HIGH TEMP REGENERATION	103.9 LB/H	
TX-0073	PETRACO VALLEY OIL & REFINING CO.; PETRACO VALLEY OIL & REFINING CO.	TX-236; 10/15/1980	REGENERATOR, FCCU; 24.9 MBBL/D		F.G. O2 CONTROL	61.2 LB/H; 0.05 % BY VOL	
TX-0073	PETRACO VALLEY OIL & REFINING CO.; PETRACO VALLEY OIL & REFINING CO.	TX-236; 10/15/1980	REGENERATOR, PLATFORMER CAT.; 0			0 TRACE	
TX-0220	FINA OIL & CHEMICAL CO.; FINA OIL & CHEMICAL CO.	18936; 08/23/1989	REGENERATOR UNIT; 0			1314 T/YR	
TX-0319	EXXON CO; EXXON MOBIL BAYTOWN REFINERY	PSD-TX-930; 09/10/1999	FLUID CATALYTIC CRACKING UNIT 2, FCCU2;		NONE INDICATED	338 LB/H; 718 T/YR	
TX-0319	EXXON CO; EXXON MOBIL BAYTOWN REFINERY	PSD-TX-930; 09/10/1999	FLUID CATALYTIC CRACKING UNIT 3, FCCU3;		NONE INDICATED	642 LB/H; 1090 T/YR	
TX-0341	DIAMOND SHAMROCK REFINING COMPANY LP; THREE RIVERS REFINERY	PSD-TX-331M1 AND 9279; 01/11/2002	FLUID CATALYTIC CRACKING UNIT, FCCU; 28000 BBL/D, ANN. AVG		NONE INDICATED	500 PPMV 1 H AV	
TX-0346	FLINT HILLS RESOURCES LP; WEST REFINERY	PSD-TX-413 (M7); 10/05/2001	FLUID CATALYTIC CRACKING UNIT (FCCU), 01BF102, AA-;		MIX WITH NAT GAS AND INCINERATE IN CO BOILER	500 PPMV	ASSUMED THE CONCENTRATION IS BY VOLUME (PPMV).
TX-0359	RELIANT ENERGY INC; LIMESTONE ELECTRIC GENERATING STATION	PSD-TX-371 (M3); 05/23/2001	FLUID CATALYTIC CRACK UNIT REGENERATOR VENT, V-20;	FUEL IS LIMITED TO NAT GAS, REFINERY FUEL GAS, FCCU REGENERATOR OFF-GAS, OR COMBINATIONS OF ANY OF THE THREE	NONE INDICATED	22.81 LB/H; 99.91 T/YR	
TX-0379	EXXONMOBIL OIL CORPORATION; EXXONMOBIL BEAUMONT REFINERY	PSD-TX-992; 06/10/2002	FCCU CO BOILER STACK (PRESCRUBBER), 06STK-001;		NONE INDICATED	457 LB/H; 2000 T/YR	

RBLCID	COMPANY NAME; FACILITY NAME	PERMIT #; ISSUANCE DATE	PROCESS NAME; THROUGHPUT	PROCESS_NOTES	CONTROL METHOD DESCRIPTION	EMISSION LIMIT(S)	POLLUTANT COMPLIANCE NOTES
TX-0379	EXXONMOBIL OIL CORPORATION; EXXONMOBIL BEAUMONT REFINERY	PSD-TX-992; 06/10/2002	FCCU SCRUBBER STACK, 06STK-003;		NONE INDICATED	911.03 LB/H; 3772.98 T/YR	
TX-0429	VALERO REFINING CO. - TEXAS; VALERO REFINING CO. - TEXAS CITY	PSD-TX-822M2; 02/23/2000	FCCU		CO BOILER	500 PPMV	
TX-0592	VALERO REFINING-TEXAS LP; CORPUS CHRISTI WEST REFINERY	38754 AND PSDTX324M13; 03/29/2010	FCCU		Preheat and control torch oil combustion limiting CO concentration to 1200 ppmv for no more than 50 hrs per	2085 LB/H; 31.3 T/YR	
TX-0673	VALERO REFINING- TEXAS, L.P.; BILL GREEHEY REFINERY	PSDTX324M14; 01/22/2014	Petroleum Refinery; 5055 MMBTU/H	CO limits are established during FCC Unit startup. All other pollutant limits are the same as for normal operations.	Valero uses good engineering practices of efficient combustion unit operation, which are BACT for this	4861.46 LB HOUR; 2945.03 TON YEAR	
VI-0001	VIRGIN ISLANDS REFINERY CORP.; VIRGIN ISLANDS REFINERY CORP.	NONE; 09/04/1981	FCC UNIT; 175000 BBL/D	The Valero Bill Greehey Refinery - West Plant takes a heavy, sour oil feed and processes and refines it to a typical slate of refinery products. It consists of numerous units and supporting equipment.		565 T/YR	
VI-0002	HESS OIL - VIRGIN ISLANDS; HESS OIL - VIRGIN ISLANDS	NONE; 02/09/1982	FCC UNIT, 2; 152734 BBL/D		CO BURNING REGENERATOR	500 PPM VOL	
VI-0003	HESS OIL VIRGIN ISLAND CORP. - HOVIC; HESS OIL VIRGIN ISLAND CORP. - HOVIC	NONE; 12/14/1990	FCC UNITS, 2; 152734 BBL/D COMB. CAP.		COMBUSTION CONTROL & HIGH TEMP REGENERATOR	432 PPMV AT 7% O2; 466.34 LB/H	
WA-0010.A	SOUND REFINING, INC.; SOUND REFINING, INC.	N/C 2439; 10/17/1983	CRACKER, FLUIDIZED BED CATALYTIC; 9010 BPD		WASTE HEAT BOILER	50 PPM	
WA-0294	CONOCO PHILLIPS 66 COMPANY; FERNDALE REFINERY	PSD-00-02 AMENDMENT 3; 06/17/2005	FCCU AND CO BOILER;			33.3 PPMDV @ 7% O2 1-H AVG; 67.9 T/YR	
WA-0317	TOSCO REFINING COMPANY; FERNDALE REFINERY	PSD-00-02; 04/04/2001	FCCU &; CO BOILER;	Process limited to operate 240 h/yr.	THERMAL OXIDATION (CO BOILER)	33.3 PPMDV 1 hr ave; 67.9 T/YR	
WI-0311	SUPERIOR REFINING COMPANY LLC; SUPERIOR REFINING COMPANY LLC	19-RAB-057; 09/27/2019	Fluid Catalytic Cracking Unit (P31); 11323 BPD		Good Combustion Practices with full-burn operation.	100 PPMVD 0% O2, 365-DAY ROLLING AVG.; 500 PPMVD 0% O2, 1-HR AVG	During startup, shutdown or hot standby, comply with limits or maintain the O2 concentration in the exhaust gas from the catalyst
Not in RBLC	Wynnewood Refining Company; Wynnewood Refinery		EUG85 - FCCU			500 PPM (HOURLY AVG); 90 PPM (ANNUAL AVG.); 7512 TPY	
Not in RBLC	Phillips 66 Company; Billings Refinery		FCCU		FULL-BURN COMBUSTION	500 PPM (HOURLY AVG.); 150 PPM (365-DAY AVG.); 133.8 TPY	
Not in RBLC	Phillips 66 Company; Borger 29 Refinery		FCCU		FULL-BURN COMBUSTION	500 PPM (HOURLY AVG.)	
Not in RBLC	Phillips 66 Company; Borger 40 Refinery		FCCU		FULL-BURN COMBUSTION	500 PPM (HOURLY AVG.)	
Not in RBLC	Phillips 66 Company; Lake Charles Refinery		FCCU		FULL-BURN COMBUSTION	500 PPM (HOURLY AVG.)	
Not in RBLC	Phillips 66 Company; Los Angeles Refinery		FCCU		FULL-BURN COMBUSTION	500 PPM (HOURLY AVG.)	
Not in RBLC	Phillips 66 Company; Sweeny 3 Refinery		FCCU		FULL-BURN COMBUSTION	500 PPM (HOURLY AVG.); 400 PPM (24-HR AVG.); 940 TPY	
Not in RBLC	Phillips 66 Company; Sweeny 27 Refinery		FCCU		FULL-BURN COMBUSTION	500 PPM (HOURLY AVG.); 400 PPM (24-HR AVG.)	

The search results are supplemented with known permit information about refineries that do not appear in the RBLC.

CO reduction can be accomplished by two general methodologies: combustion control technologies and post-combustion control methods. The following control technology options are potentially available for the control of CO emissions from FCCUs.

- Good combustion practice (High Temperature Regeneration);
- Thermal Oxidation (CO Boiler);
- Catalytic Oxidation; and

- CO Combustion Promoter.

These potential control technologies identified for the FCCUs are described in the following subsections. Information for each control device comes from technical journals and industry experience.

Control devices must be able to meet any applicable NSPS to be considered in the BACT analysis. The No. 4 FCCU and the No. 5 FCCU are both subject to NSPS, 40 CFR Part 60, Subpart Ja for emissions of CO.

VII.2.1.1 High Temperature Regeneration

Thermal formation of CO is minimized by proper furnace/combustion chamber design and operation. CO emissions are minimized by practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air.

VII.2.1.2 Thermal Oxidation (CO Boiler)

Thermal oxidization uses combustion to "control" CO emissions by converting CO and CO_2 and water. The typical thermal oxidizer for FCCUs is called a CO Boiler. Important design factors include temperature (high enough to ignite the organic constituents in the waste stream), residence time (sufficient time for the combustion reaction to occur), and turbulence or mixing of the combustion air with the waste gas.

VII.2.1.3 Catalytic Oxidation

Catalytic oxidation (CatOx) operates similar to thermal oxidation. The primary difference is that the gas, after passing through the flame area, passes through a catalyst bed in a CatOx unit. The catalyst facilitates the combustion reaction by enabling conversion at lower reaction temperatures than in thermal oxidizers. The catalyst is typically a porous noble metal material and is highly sensitive to impurities in the gas stream such as particulates. The CatOx process is also temperature sensitive; exhaust temperatures that are too high may damage the catalyst, while exhaust temperatures that are too low will reduce control efficiency. CO destruction efficiency for a CatOx unit is dependent upon exhaust composition and inlet CO concentrations, operating temperature, oxygen concentration, catalyst characteristics, and space velocity (the volumetric flow rate of gas entering the catalyst bed chamber divided by the volume of the catalyst bed).

VII.2.1.4 CO Combustion Promoter

A CO combustion promoter uses a catalyst (typically platinum or palladium) that is injected into full-burn FCCUs as needed to regenerate bed and flue gas temperatures within reliability operating limits. This can have a side effect of reducing CO emissions. It can also lead to increased NO_X emissions.

VII.2.2 Step 2 – Eliminate Technically Infeasible Control Options

The second step in the BACT analysis is to eliminate technically infeasible control technologies. Each of the control technologies is considered, and those that are clearly technically infeasible "based on physical, chemical, and engineering principles"[11] are eliminated. The following control options identified in this analysis are considered technically infeasible.

VII.2.2.1 Catalytic Oxidation

CatOx is not feasible for an FCCU, as the FCCU flue gas contains entrained particulate that would quickly foul the catalyst. There were no found uses of CatOx on FCCUs.

VII.2.3 Step 3 – Ranking of Remaining Control Technologies by Effectiveness

The third of the five steps in the top-down BACT analysis is to rank the remaining control technologies by control effectiveness.

The No. 4 FCCU and the No. 5 FCCU are both High Temperature Regeneration FCCUs, and Phillips 66 utilizes a CO combustion promoter on both units. These options are considered part of the base case for this analysis.

A CO boiler is also able to achieve a CO emission standard of 150 ppmvd.

VII.2.4 Step 4 – Top-Down Evaluation of Control Options

The remaining control technologies are evaluated on the basis of economic, energy, and environmental considerations.

VII.2.4.1 Thermal Oxidation (CO Boiler)

CO Boilers are used to control CO emissions on partial-combustion FCCUs that operate at temperatures below 1,250°F. Once the vent gas passes through the CO boiler, the CO concentrations are comparable to those of a high-temperature regeneration FCCU. The No. 4 FCCU and No. 5 FCCU both operate as full-burn, high-temperature units. Therefore, no recognizable benefit, i.e., no quantifiable CO emissions reduction, will be gained by adding a CO boiler. It would simply constitute an additional combustion source, increasing fuel usage and creating more combustion pollutants, including CO.

VII.2.4.2 High Temperature Regeneration and CO Combustion Promoter

The No. 4 FCCU and the No. 5 FCCU both use excess oxygen and high operating temperatures to reduce carbon deposits, or coke, on the FCCU catalyst and to complete the combustion of CO. CO combustion promoter is also employed in each FCCU. This base case operation is an effective

[11] U.S. EPA, New Source Review Workshop Manual (Draft): Prevention of Significant Deterioration and Nonattainment Area Permitting, October 1990.

CO control option during normal operations. However, it is not feasible during S/S/HS periods. For that reason, NESHAP, 40 CFR Part 63, Subpart UUU (Refinery MACT II) incorporates alterative monitoring to ensure that FCCU emissions are not excessive during S/S/HS periods. The Refinery MACT II allows that an affected FCCU can maintain the oxygen concentration in the exhaust gas from the catalyst regenerator at or above 1 volume percent (dry basis) or 1 volume percent (wet basis with no moisture correction) during S/S/HS periods to ensure that adequate oxygen is present to reduce CO formation.

VII.2.5 Step 5 – Selection of BACT

The fifth step in the analysis is to select the BACT emission limitation or work practice standard based on the most stringent and technically feasible control technologies that have been justified by an objective analysis of energy, environmental, and economic impacts. Based on the BACT analysis presented above, the BACT selections for the No. 4 FCCU and the No. 5 FCCU are two-fold:

- For normal operations, 150 ppmvd at 0% oxygen (365-day average) based on the use of high-temperature regeneration and CO combustion promoter; and
- For S/S/SH periods, control of excess oxygen per Refinery MACT II, i.e.,
    - 1% volume dry, or
    - oxygen > 1% volume wet.

The BACT selection is supported by recent precedents in the RBLC database, and is at least as stringent as the applicable NSPS, i.e., 500 ppmvd (1-hour average).

VII.3 BACT Analysis for Fluidized Catalytic Cracking Units – GHG Emissions

GHG emissions from FCCUs are generated by the combustion of coke, which provides the heat needed for the cracking reaction. A top-down BACT evaluation for GHG emissions from the No. 4 FCCU and the No. 5 FCCU is presented below.

VII.3.1 Step 1 – Identify All Control Technologies

Potentially applicable emission control technologies were investigated using process knowledge and engineering experience, the EPA's RBLC, and EPA's general and refinery-specific GHG BACT guidance.[12] A search of the RBLC database was performed by the applicant on January 23, 2024, to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT for the category, Petroleum Refining Conversion Processes (process Code 50.003 in the RBLC system). The search included all RBLC database entries except those that were currently under review at the time of the RBLC search. Complete search results are presented in the following table. Entries that exceeded the size of the table fields were truncated.

[12] U.S. EPA, PSD and Title V permitting Guidance for Greenhouse Gases (March 2011) and Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry (October 2010), available at https://www.epa.gov/sites/production/files/2015-12/documents/ghgpermittingguidance.pdf and https://www.epa.gov/sites/default/files/2015-12/documents/refineries.pdf (accessed on February 22, 2024).

RBLCID	COMPANY NAME; FACILITY NAME	PERMIT #; ISSUANCE DATE	PROCESS NAME; THROUGHPUT	PROCESS_NOTES	CONTROL METHOD DESCRIPTION	EMISSION LIMIT(S)	POLLUTANT COMPLIANCE NOTES
KS-0042	COFFEYVILLE RESOURCES REFINING & MARKETING, LLC; COFFEYVILLE REFINERY	CSD00079 V1.0; 10/31/2019	Fluid Catalytic Cracking Unit; 39000 BPD		Operate the FCCU as a complete-burn unit and follow operating procedures for minimizing the flaring of excess fuel gas.	439831 TONS 12 MONTH ROLLING AVERAGE	
WI-0311	SUPERIOR REFINING COMPANY LLC; SUPERIOR REFINING COMPANY LLC	19-RAB-057; 09/27/2019	Fluid Catalytic Cracking Unit (P31); 11323 BPD		Waste Heat Recovery	SEE NOTES	BACT for GHG emissions from FCCU is to comply with the CO BACT and to operate the Flue Gas Cooler and the Main Column Bottoms Steam Generator

The potential control technologies identified for the FCCUs for the control of GHG are listed below and described in the following sub sections.

- Full-Burn Operation;
- Minimization of Flaring of Excess Fuel Gas;
- Recovery of Waste Heat/Energy; and
- Carbon Capture and Sequestration.

VII.3.1.1 Full-Burn Operation

Full-burn operation with slight excess oxygen ensures efficient combustion in the FCCU "without the need for a post-combustion device[,] reducing auxiliary fuel combustion associated with a CO boiler."[13] Full-burn operation is the base case design of the No. 4 FCCU and the No. 5 FCCU.

VII.3.1.2 Minimization of Flaring of Excess Fuel Gas

The FCCU process can occasionally result in the production of more fuel gas than the refinery can utilize. The excess fuel gas can be routed to a flare for destruction, which generates GHG emissions, so minimizing the amount of flaring is an option for reducing GHG emissions overall (not at the FCCU directly). Phillips 66 operates according to a Flare Management Plan developed in accordance with NSPS, 40 CFR Part 60, Subpart Ja and NESHAP, 40 CFR Part 63, Subpart CC (Refinery MACT I). Therefore, the minimization of flaring excess fuel gas is considered part of the base case for this analysis.

VII.3.1.3 Recovery of Waste Heat/Energy

Heat/energy in the flue gas from the FCCU can be recovered to maximize the overall efficiency of the refinery. Both the No. 4 FCCU and the No. 5 FCCU utilize heat exchangers to recover heat/energy from the flue gas. Therefore, the recovery of waste heat/energy is considered part of the base case for this analysis.

VII.3.1.4 Carbon Capture and Sequestration

Carbon Capture and Sequestration (CCS) is classified by EPA as a control option that is "available' for facilities such as fossil fuel-fired electric generating units that emit CO_2 in large amounts and for industrial facilities with high-purity CO_2 streams such as those generated by hydrogen

[13] U.S. EPA, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry (October 2010), available at https://www.epa.gov/sites/default/files/2015-12/documents/refineries.pdf (accessed on February 22, 2024) at 28.

production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing. CCS is not an available control option for refinery FCCUs, which generates low-purity CO_2 streams.

VII.3.2 Step 2 – Eliminate Technically Infeasible Control Options

Except for CSS, all the control options identified in Step 1 are technically feasible.

VII.3.2.1 Technical Infeasibility of CCS

Per the NSR Workshop Manual, "two key concepts are important in determining whether an undemonstrated technology is feasible: 'availability' and 'applicability.'" A technology is available if it "can be obtained…through commercial channels," and it is applicable if it "can be reasonably installed and operated on the source type."

There are three main CCS alternatives. Geologic storage of CO_2 is still being developed/tested by the U.S. Department of Energy (DOE) National Energy, Technology Laboratory (NETL). For example, aspects of CCS undergoing testing include the performance of the containment and the potential for interference with groundwater. Similarly, CO_2 injection for the purpose of coal bed methane (CBM) recovery is also in the research stage. The use of CO_2 enhanced oil recovery (EOR) is also infeasible because EOR demands for CO_2 decrease substantially over time whereas a CO_2 stream from a refinery FCCU is steady, year after year, resulting in the eventual venting of the excess CO_2. For these reasons, CCS is not available and is not technically feasible.

VII.3.3 Step 3 – Ranking of Remaining Control Technologies by Effectiveness

No ranking is needed because all of the technically feasible control options are part of the based case operations.

VII.3.4 Step 4 – Top-Down Evaluation of Control Options

No evaluation is needed because all of the technically feasible control options are part of the base case operations.

VII.3.5 Step 5 – Selection of BACT

BACT for GHG emissions from the No. 4 FCCU and the No. 5 FCCU are based on full-burn operation, and recovery of waste heat/energy, as well as minimization of flaring of excess fuel gas through compliance with the Flare Management Plan. The GHG emission limits for the No. 4 FCCU and the No. 5 FCCU are 241,000 TPY CO_{2E} and 382,700 TPY CO_{2e}, respectively, based on the calculation methodology in 40 CFR § 98.253(c)(2)(i), Equation Y-6.[14]

[14] The equation Y-6 inputs are 2,808,990 dry standard cubic feet per day (dscf/day), 95 ppmv CO, and 17.1% CO_2 for the No. 4 FCCU and 4,168,711 dscf/day, 155 ppmv CO and 16.6% CO_2, for the No. 5 FCCU.

SECTION VIII. AMBIENT AIR IMPACTS ANALYSIS

Since the total facility-wide net emissions increase associate with the project exceed the PSD significant emission rate (SER) for CO, an ambient air impacts analysis is required. The analysis must demonstrate that ambient impacts of CO due to emissions from the proposed project do not cause or contribute to a violation of a National Ambient Air Quality Standard (NAAQS) or exceed a PSD Increment. Additionally, all PSD permit applications must address additional impacts (i.e., impacts to growth, soils, vegetation, and visibility) and impacts to Class I areas. Each aspect of the ambient air impact analysis is addressed in the following section(s).

Currently, there are no PSD increments for emissions of CO; therefore, a PSD increment analysis is not required.

VIII.1 NAAQS Modeling for CO

VIII.1.1 Modeling Methodology

VIII.1.1.1 Model Selection

The American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) (version 22112) was used for the modeling analysis. AERMOD is a steady-state plume dispersion model used for assessment of pollutant concentrations from a variety of sources and is the primary model used for conducting refined modeling analyses. AERMOD incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain.

VIII.1.1.2 Terrain

Following Oklahoma DEQ guidance, modeling with elevated terrain was used for this analysis. AERMAP (version 18081), a terrain preprocessor that incorporates complex terrain using U.S. Geological Survey 9USGS) Digital Elevation data was used to determine stack, building, and receptor elevations/hill heights. Elevations entered into the model were obtained using the National Elevation Dataset (NED), the primary elevation data product of USGS.

VIII.1.1.3 Stack GEP Analysis & Building Downwash

Building wake effects on each emission point source were incorporated through the use of the BPIP-PRIME (version 04274) algorithm. BPIP-PRIME calculates all direction specific building data required by the air dispersion model to enable it to include the appropriate building downwash algorithm in the calculations. The structure dimensions are then imported into AERMOD on an emission point-specific basis. Detailed building data is included in the tables below.

Building Parameters – Rectangular

ID	Easting	Northing	Elevation	Height	X Length	Y Length	Angle
	meter	meter	meter	feet	feet	feet	Deg.
COOLTOW	671,356.5	4,061,007.7	304.92	39.99	60.93	264.07	0

ID	Easting	Northing	Elevation	Height	X Length	Y Length	Angle
	meter	meter	meter	feet	feet	feet	Deg.
BLD-264	671,242.0	4,061,110.4	305.42	14.99	32.81	31.27	90
PROCS4	671,204.8	4,061,073.3	305.17	39.99	23.43	50.00	88
PROCS5	671,203.9	4,061,045.7	305.04	39.99	10.93	35.93	1
PROCS6	671,203.9	4,061,030.0	304.96	14.99	203.12	31.27	-3.3
PROCS7	671,202.9	4,061,017.4	304.80	50.00	56.27	43.77	0
PROCS8	671,202.0	4,060,986.2	304.73	14.99	60.93	37.50	0
D-5035	671,218.5	4,060,981.7	304.70	14.99	45.31	10.93	0
BLD-256	671,245.2	4,060,988.4	304.76	14.99	25.00	23.43	2.7
PROCS9	671,261.9	4,061,008.2	304.74	50.00	38.39	262.80	90
PROCS10	671,290.0	4,061,067.5	305.16	29.99	24.28	33.46	88.5
TOOLRM	671,273.2	4,061,090.8	305.31	20.01	43.77	68.77	90
BLD-257	671,329.4	4,061,079.9	305.21	14.99	25.00	21.88	0
BLD-261	671,359.3	4,061,096.8	305.41	29.99	25.00	31.27	0
PROCS14	671,196.2	4,062,490.6	301.14	25.00	32.81	65.62	0
PROCS15	671,148.3	4,062,433.8	301.23	50.00	16.73	63.32	90
H-6012BS	671,145.1	4,062,418.4	301.57	35.01	14.11	28.12	90
H-6013BS	671,158.4	4,062,418.7	301.42	45.01	14.11	29.69	90
PROCS16	671,134.7	4,062,367.6	299.07	14.99	64.07	250.00	88.4
BLD-346	671,171.3	4,061,834.8	297.40	12.01	20.31	35.93	43
BLD-359	671,177.4	4,061,845.1	297.42	14.99	23.43	56.27	43
BLD-188	671,081.7	4,061,650.3	298.87	40.00	40.62	60.93	0
BLD-374	671,015.4	4,061,721.7	299.97	29.99	33.79	32.81	92.2
PROCS22	671,011.7	4,061,702.4	299.20	39.99	56.27	56.27	90.3
H-7501BS	671,088.1	4,061,596.6	299.13	39.99	10.93	18.77	0
BLD-158	671,025.9	4,061,560.0	300.15	20.00	48.43	25.00	0
COOLTW	671,071.5	4,061,376.3	302.85	60.01	65.94	17.39	88
BLD-180	671,021.5	4,061,309.0	301.19	12.01	31.27	25.00	0
PROCS25	671,010.9	4,061,304.1	301.12	14.99	9.35	12.50	0
PROCS26	671,011.4	4,061,295.4	301.82	14.99	12.50	20.01	357.3
BLD-236	671,163.8	4,060,912.6	304.45	20.01	29.69	100.00	0
PROCS31	671,143.5	4,060,939.4	304.98	12.01	24.93	106.27	0
PROCS32	671,143.0	4,060,957.3	305.05	20.01	37.40	43.77	-90
D-5292	671,177.7	4,060,973.2	304.87	14.99	35.93	9.35	0
BOILER7	670,897.0	4,061,965.6	305.22	45.01	15.62	37.50	0
D-339	670,816.6	4,061,772.1	303.26	10.01	6.23	12.47	180
H-0010	670,801.4	4,061,778.7	303.30	29.99	9.38	50.00	-8.1
H-1	670,791.9	4,061,858.1	303.60	50.00	37.50	50.00	0
D-94	670,792.0	4,061,769.0	302.78	14.99	62.50	12.50	0
PROCS46	670,774.3	4,061,848.4	303.42	40.00	37.50	25.00	0
BLD-150	670,676.5	4,061,597.5	301.36	25.00	12.50	7.81	0
Y-2CLT1	670,691.8	4,061,816.6	301.94	39.99	62.50	96.78	0

ID	Easting	Northing	Elevation	Height	X Length	Y Length	Angle
	meter	meter	meter	feet	feet	feet	Deg.
Y-2CLT2	670,694.6	4,061,791.8	301.77	39.99	53.12	75.00	0
CFIBER1	671,570.2	4,060,463.1	296.08	50.00	137.80	311.68	90
CFIBER2	671,665.2	4,060,478.1	296.20	50.00	124.67	288.71	90
CFIBER3	671,665.2	4,060,440.1	296.13	50.00	39.37	88.58	90
CFIBER4	671,753.2	4,060,467.1	296.16	50.00	203.41	200.13	90
CFIBER5	671,814.2	4,060,548.1	295.91	50.00	469.16	101.71	90
CFCOOLTW	670,775.5	4,061,951.3	303.87	39.99	23.43	67.91	90
H-8602	670,721.4	4,062,035.3	303.84	135.00	30.51	14.11	0
H-8601	670,713.3	4,062,062.1	303.73	135.00	80.00	18.77	0
YZJU1002	671,105.7	4,062,633.5	305.11	30.00	187.66	46.92	90
YZJU1003	671,129.2	4,062,647.8	305.14	30.00	67.91	136.15	90
BLDG0372	670,309.8	4,061,692.9	303.23	15.00	89.24	62.99	90
DRUM	670,360.5	4,062,567.0	302.81	15.00	154.86	37.73	180
RESINBLG	670,238.0	4,062,568.3	302.40	15.00	184.06	54.46	180
U43ALKY	670,826.4	4,061,548.5	301.57	40.00	300.00	81.69	-180
ALKYOFF	670,676.2	4,061,514.1	302.27	20.00	187.66	197.51	90
DRUMS2	670,690.0	4,061,578.4	301.77	20.00	62.01	70.21	90
H60	670,818.9	4,061,490.3	302.09	50.00	143.70	40.68	90
SUB321	670,889.6	4,061,676.0	302.01	15.00	50.00	50.00	90
HGBF6009	671,371.6	4,060,196.5	295.13	20.00	41.34	32.81	180
BLD404	671,293.7	4,059,956.7	294.57	20.00	131.89	86.61	90
BLD291	671,164.3	4,061,550.4	300.84	20.00	58.73	97.77	180
BLD8001	671,318.9	4,061,612.4	303.11	20.00	76.44	65.29	180
BLD126	671,287.6	4,061,592.0	303.02	20.00	65.62	29.86	-90
P1390	671,077.6	4,061,729.4	298.29	40.00	14.76	74.48	180
O7507	671,078.2	4,061,573.8	299.60	50.00	29.86	20.34	180
H7501	671,085.6	4,061,586.9	299.45	70.00	18.70	11.15	90
BLD157	671,035.6	4,061,589.7	299.84	15.00	35.10	42.98	180
BLD155	671,010.1	4,061,598.8	300.21	30.00	181.76	50.20	-180
BLD64	671,003.2	4,061,682.3	299.83	110.00	80.00	110.00	180
HGBF600K	671,020.8	4,061,680.0	299.11	40.00	25.00	100.00	90
BLD338	670,702.2	4,061,759.6	302.02	20.00	50.00	70.00	90
BLD82	670,742.6	4,061,723.5	301.20	20.00	45.00	20.00	-90
LBD96	670,767.1	4,061,794.6	302.87	20.00	30.00	65.00	180
BLD86	670,732.9	4,061,813.5	302.71	20.00	40.00	65.00	90
BLD37	670,796.7	4,061,842.5	303.81	20.00	50.00	100.00	90
W1AREA	670,757.4	4,061,855.5	303.42	40.00	95.00	95.00	0
HGBF600R	670,738.5	4,061,884.6	303.09	40.00	95.00	40.00	90
HGBF600S	670,738.5	4,061,884.6	303.09	40.00	40.00	47.50	180
PA19	670,837.2	4,061,859.0	304.90	50.00	30.00	65.00	90
H5	670,857.1	4,061,888.7	304.94	60.00	35.00	45.00	180

ID	Easting	Northing	Elevation	Height	X Length	Y Length	Angle
	meter	meter	meter	feet	feet	feet	Deg.
BLD171	670,838.9	4,061,816.6	303.90	20.00	45.00	85.00	90
FRACTANK	670,802.1	4,061,957.7	304.32	15.00	25.00	65.00	90
BLD43	670,898.8	4,062,029.1	305.39	30.00	25.00	40.00	90
BLD22	670,702.7	4,061,994.8	302.70	20.00	30.00	40.00	180
BLD84	670,700.4	4,062,022.7	303.25	20.00	14.00	20.00	-180
HGBF6012	670,768.6	4,062,124.6	303.85	45.00	18.77	18.77	90
HGBF6013	670,768.7	4,062,117.1	303.86	45.00	18.77	18.77	90
BLD32	670,765.9	4,062,101.1	303.89	40.00	60.00	60.00	90
BLD30	670,789.4	4,062,101.1	303.97	40.00	60.00	60.00	90
H9051	670,705.9	4,062,135.5	303.91	50.00	100.00	55.00	180
D9056	670,708.0	4,062,137.6	303.95	30.00	75.00	40.00	90
F9051	670,723.1	4,062,131.8	303.87	20.00	40.00	40.00	90
B10	670,850.8	4,062,072.4	305.13	50.00	15.00	80.00	90
B9	670,850.8	4,062,057.3	305.17	50.00	15.00	80.00	90
B9901	670,684.0	4,062,205.3	304.27	40.00	35.00	80.00	90
B9902	670,684.0	4,062,173.6	304.18	40.00	35.00	80.00	90
HYD10PRO	670,988.9	4,061,368.1	300.69	40.00	90.00	90.00	90
BLD115	671,017.2	4,061,386.9	300.69	30.00	210.00	40.00	90
BLD83	671,124.1	4,062,567.5	304.10	20.00	40.00	65.00	90
BLD342	671,095.3	4,062,507.7	303.12	20.00	15.00	50.00	90
BLD348	671,099.2	4,062,517.9	302.96	20.00	25.00	50.00	90
BLD356	671,102.1	4,062,530.3	302.73	20.00	15.00	35.00	90
BLD320	671,148.9	4,062,760.0	305.85	20.00	45.00	90.00	90
BLD369	670,987.3	4,060,842.2	301.37	20.00	70.00	35.00	68.6
HYPDH00B	670,971.0	4,061,109.6	301.46	20.00	90.00	50.00	90
HYPDH00C	671,019.6	4,061,060.1	302.20	40.00	65.00	50.00	90
BLD366	670,952.7	4,060,981.5	301.46	30.00	205.00	50.00	76.6
BLD365	670,962.1	4,061,006.3	301.60	20.00	45.00	20.00	88.2
HYPDH00F	670,978.0	4,061,036.2	301.59	20.00	55.00	55.00	90
HYPDH00G	670,984.5	4,061,015.6	301.76	20.00	35.00	20.00	90

Building Parameters – Circular (Tanks)

ID	Easting	Northing	Elevation	Height	Radius	Corners
	meters	meters	meters	feet	feet	
T-107E	671,224.1	4,062,611.5	301.61	31.99	39.01	24
T-106E	671,263.1	4,062,644.5	302.83	31.99	39.01	24
T-14E	671,230.1	4,062,572.5	301.40	43.01	16.01	24
T-6601	671,271.1	4,062,479.5	300.43	25.00	4.99	24
T-17E	671,282.1	4,062,319.5	299.81	42.68	22.01	24
T-702	671,279.1	4,062,284.5	300.07	27.99	19.75	24
T-705	671,278.1	4,062,269.5	300.18	29.40	19.75	24

ID	Easting	Northing	Elevation	Height	Radius	Corners
	meters	meters	meters	feet	feet	
T-706	671,280.1	4,062,247.5	300.54	29.49	19.75	24
T-701	671,298.1	4,062,283.5	301.73	28.08	19.75	24
T-704	671,298.1	4,062,269.5	301.81	29.49	19.75	24
T-703	671,281.1	4,062,258.5	300.88	30.41	6.00	24
T-16E	671,237.1	4,062,308.5	299.30	14.50	17.49	24
T-21E	671,278.1	4,061,744.8	301.12	39.57	60.01	24
T-974	671,399.2	4,061,013.0	305.09	30.09	12.50	24
T-973	671,398.2	4,061,027.0	305.14	29.66	17.49	24
T-945	671,229.2	4,061,106.0	305.39	29.99	17.49	24
T-909	671,205.2	4,060,852.0	303.48	41.67	25.98	24
T-908	671,207.2	4,060,891.0	303.63	41.77	32.74	24
T-914	671,205.2	4,060,930.0	304.23	41.83	32.74	24
T-913	671,242.2	4,060,933.0	303.90	41.67	32.74	24
T-907	671,243.2	4,060,896.0	303.65	41.93	32.74	24
T-910	671,243.2	4,060,853.0	303.22	41.77	25.98	24
T-906	671,278.2	4,060,895.0	303.62	41.57	32.74	24
T-944	671,276.2	4,060,935.0	303.98	41.40	32.74	24
T-917	671,299.2	4,060,978.0	304.68	37.99	19.00	24
T-921	671,284.2	4,060,977.0	304.66	30.41	15.22	24
T-920	671,270.2	4,060,976.0	304.74	30.41	15.22	24
T-919	671,248.2	4,060,976.0	304.74	30.41	14.99	24
T-918	671,233.2	4,060,976.0	304.65	30.41	15.22	24
T-916	671,217.2	4,060,975.0	304.71	18.01	12.50	24
T-915	671,310.2	4,060,936.0	304.27	30.25	17.49	24
T-976	671,400.2	4,060,980.0	304.79	40.09	21.26	24
T-39E	671,189.1	4,062,557.5	302.22	37.99	19.00	24
T-208E	671,099.1	4,062,444.5	301.88	31.99	16.77	24
T-211E	671,141.1	4,062,335.5	298.61	25.49	10.01	24
T-551	671,112.1	4,061,774.8	298.70	35.50	24.25	24
T-554	671,112.1	4,061,796.8	298.85	27.99	19.75	24
T-553	671,087.1	4,061,795.8	298.75	27.99	19.75	24
T-552	671,091.1	4,061,773.8	298.79	35.50	24.25	24
T-500	671,116.1	4,061,838.8	297.30	47.83	50.00	24
T-555	671,095.1	4,061,761.8	298.65	29.99	6.00	24
T-501	671,089.1	4,061,740.8	298.32	28.51	18.50	24
T-12	671,021.1	4,061,728.8	299.91	39.99	14.99	24
T-536	671,064.1	4,061,676.8	298.65	20.01	6.00	24
T-515	671,054.1	4,061,471.8	301.21	27.00	18.50	24
T-514	671,051.1	4,061,496.8	300.64	27.00	18.50	24
T-512	671,051.1	4,061,541.8	300.26	27.17	18.50	24
T-15	671,018.1	4,061,236.8	302.98	39.99	24.02	24

ID	Easting	Northing	Elevation	Height	Radius	Corners
	meters	meters	meters	feet	feet	
T-540	671,048.1	4,061,246.8	304.16	32.19	14.99	24
T-80	670,867.3	4,061,605.4	301.26	33.33	12.50	24
T-990	671,056.2	4,061,019.0	303.92	17.09	25.00	24
T8500..	671,146.2	4,061,101.0	306.65	31.59	5.09	24
T-992	671,068.2	4,061,021.0	304.23	16.01	4.00	24
T-991	671,068.2	4,061,016.0	304.23	16.01	4.00	24
T-989	671,067.2	4,061,004.0	304.00	12.01	6.00	24
T-447	670,844.3	4,061,921.4	305.17	25.49	12.76	24
T-51	670,885.3	4,061,746.4	303.05	29.76	39.01	24
T-64	670,785.3	4,061,667.4	301.32	33.07	21.78	24
T-66	670,755.3	4,061,607.4	301.58	30.25	15.12	24
T-70	670,726.3	4,061,606.4	301.70	29.00	25.00	24
T-77	670,703.3	4,061,606.4	301.56	29.99	17.49	24
T-205	670,679.3	4,061,664.4	301.05	35.50	24.25	24
T-204	670,677.3	4,061,688.4	301.22	35.50	24.25	24
T-37	670,659.3	4,061,664.4	300.74	42.42	21.26	24
T-38	670,658.3	4,061,693.4	301.09	39.99	20.05	24
T-202	670,638.3	4,061,664.4	300.80	35.50	24.25	24
T-201	670,633.3	4,061,685.4	300.83	35.50	24.25	24
T-34	670,798.3	4,061,726.4	301.67	19.32	14.99	24
T-33	670,785.3	4,061,727.4	301.64	10.01	7.51	24
T-30	670,810.3	4,061,725.4	301.99	10.99	6.00	24
T-203	670,693.3	4,061,673.4	301.37	24.02	6.00	24
T-253	670,676.3	4,061,608.4	301.23	24.02	7.51	24
T-254	670,676.3	4,061,601.4	301.30	16.01	6.00	24
T-31	670,797.3	4,061,739.4	301.66	12.01	4.99	24
T-509	670,687.3	4,061,609.4	301.22	15.81	10.63	24
T-256	670,726.3	4,061,573.4	301.83	34.68	4.99	24
T-503	670,718.3	4,061,577.4	301.82	31.50	6.00	24
T-114	670,518.5	4,061,469.4	303.21	29.92	25.00	24
T-101	670,511.5	4,061,602.4	302.82	29.99	25.00	24
T-183	670,454.5	4,061,521.7	304.98	50.98	25.49	24
T-182	670,454.5	4,061,497.7	304.47	50.98	25.49	24
T-181	670,455.5	4,061,473.7	304.49	50.98	25.49	24
T-168	670,524.5	4,061,334.4	305.14	39.99	21.26	24
T-180	670,454.5	4,061,445.7	304.44	60.50	30.25	24
T-178	670,423.5	4,061,402.7	304.65	58.17	22.51	24
T-177	670,421.5	4,061,418.7	305.44	30.51	12.76	24
T-179	670,448.5	4,061,401.7	305.36	20.01	10.01	24
T-402	670,544.2	4,061,280.3	304.46	14.01	6.00	24
T-106	670,367.4	4,061,875.0	301.79	29.59	57.25	24

ID	Easting	Northing	Elevation	Height	Radius	Corners
	meters	meters	meters	feet	feet	
T-107	670,353.4	4,061,715.0	302.92	29.99	56.27	24
T-167	670,308.5	4,061,407.7	303.99	37.43	39.37	24
T-170	670,310.5	4,061,309.7	304.86	30.18	39.01	24
T-169	670,527.5	4,061,289.4	305.55	39.99	21.26	24
T-176	670,391.5	4,061,402.7	304.24	42.91	36.68	24
T-136	669,580.2	4,062,514.3	304.79	50.00	62.37	24
T-135	669,733.2	4,062,513.3	304.95	50.00	62.37	24
T-130	669,737.2	4,062,340.3	304.60	50.00	76.25	24
T-131	669,577.1	4,062,344.0	304.59	50.00	76.25	24
T-125	669,578.2	4,062,188.1	305.14	50.00	56.00	24
T-126	669,579.2	4,062,034.9	304.88	50.00	56.00	24
T-151	669,575.4	4,061,721.1	303.23	42.09	58.50	24
T-123	669,731.2	4,062,185.3	305.63	50.00	56.00	24
T-124	669,737.2	4,062,032.2	305.59	50.00	56.00	24
T-150	669,731.4	4,061,722.1	303.75	41.99	58.50	24
T-129	669,887.2	4,062,352.3	307.17	50.00	55.51	24
T-144	669,902.2	4,061,874.3	305.71	48.00	76.74	24
T-149	669,893.2	4,061,723.3	304.25	41.99	58.50	24
T-128	670,044.9	4,062,350.0	306.92	50.00	55.51	24
T-119	670,047.2	4,062,178.3	305.45	48.00	91.01	24
T-120	670,052.2	4,062,047.3	305.74	48.00	99.11	24
T-143	670,052.2	4,061,876.3	304.21	48.00	76.74	24
T-148	670,043.4	4,061,719.6	304.22	41.99	58.50	24
T-117	670,180.1	4,062,176.6	304.93	48.00	91.01	24
T-142	670,197.4	4,061,878.6	303.49	40.16	60.01	24
T-147	670,198.4	4,061,721.6	303.69	39.99	60.01	24
T-156	669,577.4	4,061,561.1	302.78	47.57	58.50	24
T-161	669,580.4	4,061,406.1	302.19	41.83	58.50	24
T-166	669,570.6	4,061,251.1	301.98	48.00	60.01	24
T-155	669,732.4	4,061,565.1	303.57	41.99	58.50	24
T-160	669,733.4	4,061,407.1	302.68	41.83	58.50	24
T-165	669,719.8	4,061,249.2	302.23	40.26	60.01	24
T-154	669,894.2	4,061,565.3	304.33	48.00	75.00	24
T-159	669,887.5	4,061,408.3	303.32	42.16	58.50	24
T-164	669,882.6	4,061,250.4	302.80	41.67	58.50	24
T-153	670,050.2	4,061,566.3	304.68	41.77	58.50	24
T-158	670,044.4	4,061,404.6	304.44	41.67	58.50	24
T-163	670,048.4	4,061,249.6	304.00	41.40	58.50	24
T-152	670,194.5	4,061,556.9	303.92	41.99	58.50	24
T-162	670,198.5	4,061,248.7	304.05	41.17	58.50	24
T-610	669,876.2	4,061,093.6	302.72	41.50	58.50	24

ID	Easting	Northing	Elevation	Height	Radius	Corners
	meters	meters	meters	feet	feet	
T-613	669,883.9	4,060,700.3	302.45	41.34	58.50	24
T-614	669,886.9	4,060,569.3	301.52	41.34	58.50	24
T-615	669,887.9	4,060,433.3	300.09	41.83	58.50	24
T-609	669,742.1	4,060,463.6	300.03	40.09	60.01	24
T-616	670,038.2	4,061,095.0	303.82	41.50	58.50	24
T-617	670,040.2	4,060,962.0	303.90	41.57	58.50	24
T-618	670,041.2	4,060,831.0	304.18	41.67	58.50	24
T-620	670,036.7	4,060,564.4	303.20	41.67	58.50	24
T-621	670,037.7	4,060,433.4	300.53	41.77	58.50	24
T-625	670,183.7	4,060,696.3	301.25	41.57	58.50	24
T-626	670,189.7	4,060,562.3	300.56	41.67	58.50	24
T-627	670,191.7	4,060,430.3	298.96	41.34	58.69	24
T-629	670,363.4	4,060,928.3	303.92	41.83	58.50	24
T-630	670,367.1	4,060,771.8	303.03	41.50	58.50	24
T-631	670,371.1	4,060,594.8	300.77	41.67	58.50	24
T-633	670,484.0	4,061,088.3	305.34	39.99	60.01	24
T-636	670,488.1	4,060,701.8	303.94	41.40	58.66	24
T-639	670,603.0	4,061,093.3	302.11	28.58	58.50	24
T-651	670,827.2	4,060,109.5	295.31	41.83	58.50	24
T-652	670,834.2	4,059,951.5	294.58	41.50	58.50	24
T-653	670,838.2	4,059,803.5	293.37	41.57	58.50	24
T-663	670,810.5	4,059,731.8	293.58	16.99	50.00	24
T-661	670,811.5	4,059,691.8	293.53	22.01	52.49	24
T-654	670,831.5	4,059,647.8	291.47	37.99	58.69	24
T-660	670,851.5	4,059,693.8	293.36	22.01	52.49	24
T-670	670,849.5	4,059,734.8	293.70	14.50	50.00	24
T-665	670,893.5	4,059,691.8	293.26	48.26	57.51	24
T-669	670,892.5	4,059,730.8	293.48	29.49	19.75	24
T-662	670,777.5	4,059,726.8	290.66	19.00	17.49	24
T-664	670,791.5	4,059,739.8	293.79	15.42	4.49	24
T-671	670,830.5	4,059,748.8	293.62	16.01	4.27	24
T-901	671,161.2	4,060,431.0	297.02	41.40	58.50	24
T-902	671,279.2	4,060,426.1	296.26	41.77	58.50	24
T-903	671,285.6	4,060,556.1	298.31	41.77	58.50	24
T-953	671,413.6	4,060,561.1	297.24	39.83	50.00	24
T-904	671,409.2	4,060,429.1	295.88	41.24	58.50	24
T-905	671,415.2	4,060,292.1	294.97	41.24	58.50	24
T-958	671,177.5	4,060,560.0	298.86	43.50	34.19	24
T-957	671,245.2	4,060,678.0	300.34	37.99	19.00	24
T-956	671,247.2	4,060,709.0	301.10	37.99	19.00	24
T-975	671,420.2	4,060,995.0	305.14	30.91	45.01	24

ID	Easting	Northing	Elevation	Height	Radius	Corners
	meters	meters	meters	feet	feet	
T-667	670,918.5	4,059,666.8	293.76	24.02	6.00	24
W6039	671,233.1	4,062,483.5	300.85	73.49	2.49	24
W6020	671,227.1	4,062,483.5	300.86	25.00	1.35	24
W6017	671,225.1	4,062,448.5	300.42	78.61	5.25	24
W6038(T)	671,226.1	4,062,434.5	300.24	33.01	8.01	24
W6037(B)	671,226.1	4,062,434.5	300.24	45.73	12.01	24
D6101	671,231.1	4,062,426.5	300.21	39.50	6.27	24
D6102	671,223.1	4,062,427.5	299.95	44.32	8.01	24
W5001	671,213.2	4,061,052.0	305.07	81.30	6.99	24
D5131	671,229.2	4,061,053.0	305.08	20.01	2.49	24
D5164	671,225.2	4,061,026.0	304.95	39.99	4.76	24
D5357	671,208.2	4,061,005.0	304.84	73.39	2.76	24
D5358	671,216.2	4,061,005.0	304.90	12.01	2.99	24
D5180	671,253.2	4,061,089.0	305.30	35.01	3.31	24
D5179	671,258.2	4,061,089.0	305.28	35.01	3.25	24
W5079	671,275.2	4,061,065.0	305.22	54.00	2.99	24
D5166	671,280.2	4,061,065.0	305.29	23.92	3.74	24
W5058	671,284.2	4,061,065.0	305.20	39.99	4.99	24
W5054	671,287.2	4,061,043.0	304.99	39.99	2.00	24
W5073	671,264.2	4,061,011.0	304.74	63.29	3.51	24
W5072	671,269.2	4,061,011.0	304.76	73.39	2.76	24
W5033	671,272.2	4,061,011.0	304.77	77.99	2.49	24
W5039	671,286.2	4,061,011.0	304.99	70.01	2.00	24
W6026	671,291.2	4,061,011.0	304.92	89.01	4.27	24
W5071	671,319.2	4,061,051.0	305.15	78.18	3.25	24
D161	671,304.2	4,061,058.0	305.10	35.50	2.99	24
W5062	671,304.2	4,061,011.0	304.81	66.50	3.51	24
W5063	671,310.2	4,061,011.0	304.82	128.51	8.99	24
W5066	671,317.2	4,061,011.0	304.82	55.51	3.35	24
W5067	671,322.2	4,061,011.0	304.83	83.76	2.49	24
W5082	671,336.2	4,061,011.0	304.86	81.50	2.00	24
W5081	671,342.2	4,061,011.0	304.86	62.99	3.51	24
D6122	671,200.1	4,062,504.5	301.02	13.68	3.51	24
W6016	671,202.1	4,062,501.5	301.04	60.01	2.26	24
W6023	671,200.1	4,062,496.5	301.10	45.01	1.74	24
W6022	671,202.1	4,062,496.5	301.08	16.99	2.76	24
W6019	671,196.1	4,062,490.5	301.14	112.99	3.51	24
D6931	671,138.1	4,062,472.5	302.71	12.66	2.00	24
W6031	671,138.1	4,062,461.5	302.64	68.01	2.26	24
W6025	671,138.1	4,062,446.5	302.66	58.01	3.25	24
D565	671,159.1	4,062,446.5	301.05	20.01	3.74	24

ID	Easting	Northing	Elevation	Height	Radius	Corners
	meters	meters	meters	feet	feet	
W6009	671,134.1	4,062,390.5	299.98	77.00	8.99	24
W6012	671,188.1	4,062,398.5	300.35	125.00	6.99	24
W6001	671,167.1	4,062,379.5	299.44	68.77	6.00	24
W6007	671,168.1	4,062,370.5	298.90	52.00	2.26	24
W6005	671,196.1	4,062,381.5	299.24	82.09	4.49	24
D6119	671,112.1	4,062,428.5	301.61	31.99	2.00	24
W79	671,092.1	4,061,717.8	298.29	42.49	6.99	24
D-502	671,087.1	4,061,616.8	298.93	61.32	4.27	24
D7502	671,087.1	4,061,573.8	299.62	34.51	5.51	24
D7501	671,077.1	4,061,577.8	299.65	24.02	4.00	24
D5140	671,165.2	4,061,008.0	304.92	64.99	6.50	24
D5139	671,171.2	4,061,009.0	304.94	45.01	6.50	24
D5190(T)	671,180.2	4,061,010.0	305.06	45.51	4.00	24
D5191(B)	671,180.2	4,061,010.0	305.06	2.59	5.09	24
W-5101	670,845.3	4,061,936.4	305.24	149.02	12.14	24
D-327	670,844.3	4,061,929.4	305.19	24.02	10.01	24
D-326	670,844.3	4,061,915.4	305.17	24.02	10.01	24
D-337	670,844.3	4,061,911.4	304.97	48.49	4.99	24
D-338	670,874.3	4,061,911.4	305.02	48.49	4.99	24
W-19	670,839.3	4,061,865.4	304.99	38.68	4.49	24
W-21	670,847.3	4,061,865.4	305.03	35.33	6.00	24
W-22(T)	670,865.3	4,061,859.4	304.99	77.99	5.25	24
W-29	670,874.3	4,061,859.4	304.94	12.99	1.74	24
W-36(G)	670,886.3	4,061,864.4	304.81	50.49	10.50	24
W-42	670,912.3	4,061,784.4	304.21	95.01	3.74	24
D-805	670,845.3	4,061,782.4	303.61	25.00	4.27	24
W-18	670,817.3	4,061,807.4	303.38	72.93	7.51	24
W-82	670,996.1	4,061,633.8	300.43	75.00	9.51	24
W-83	670,996.1	4,061,641.8	300.45	75.00	9.51	24
D-5211	670,813.3	4,061,690.4	301.74	16.99	5.51	24
W-32	670,865.3	4,061,578.4	301.04	58.01	3.51	24
D-492	670,865.3	4,061,568.4	301.01	19.65	4.49	24
D-491	670,865.3	4,061,558.4	301.15	16.17	4.27	24
D-375	670,984.1	4,061,410.8	300.65	37.34	5.51	24
D-126	670,993.1	4,061,388.8	300.66	28.41	5.74	24
D-27	670,994.1	4,061,384.8	300.69	37.50	4.27	24
W-1	670,778.7	4,061,874.6	303.46	124.34	7.74	24
D-248	670,783.3	4,061,753.4	301.56	29.76	6.50	24
D-235	670,783.3	4,061,745.4	301.62	29.99	6.50	24
D-427	670,784.3	4,061,735.4	301.60	13.62	1.74	24
D-130	670,787.3	4,061,735.4	301.60	23.29	2.99	24

ID	Easting	Northing	Elevation	Height	Radius	Corners
	meters	meters	meters	feet	feet	
D-5212	670,808.3	4,061,690.4	301.62	19.16	5.51	24
W-193	670,780.3	4,061,556.4	301.70	200.49	8.01	24
W-195	670,809.3	4,061,557.4	301.76	68.18	2.99	24
W-190	670,824.3	4,061,576.4	301.71	81.33	2.49	24
T-121NEW	669,887.2	4,062,172.9	306.68	39.99	55.00	24
T-157NEW	670,207.5	4,061,407.7	304.08	39.99	66.99	24
H2-FURN1	670,672.3	4,062,089.4	303.03	40.03	8.01	24
H2-FURN2	670,688.3	4,062,089.4	303.43	40.03	8.01	24
H2-STOR	670,680.3	4,062,076.4	303.02	60.01	4.99	24
ULSD1	671,038.1	4,061,453.8	301.21	85.01	4.00	24
ULSD2	671,047.1	4,061,453.8	301.55	75.00	6.99	24
YZJU1000	671,139.4	4,060,558.0	298.78	43.50	34.19	24
D46	670,846.7	4,061,839.9	304.45	30.00	10.00	24

Building Parameters – Polygon (Non-Rectangular, Non-Circular)

ID	Easting	Northing	Elevation	Height	Corners
	meters	meters	meters	feet	
Y-6026	671,279.5	4,062,584.6	302.28	39.99	4
BLD-351	671,259.0	4,062,520.4	300.78	14.99	4
BLD-303	671,238.4	4,062,522.2	301.08	14.99	4
PROCS1	671,220.2	4,062,476.1	300.87	129.99	4
BASEFCC	671,234.8	4,062,431.0	300.32	100.00	4
PROCS2	671,208.9	4,062,423.2	299.54	25.00	24
H-6015	671,224.1	4,062,368.9	298.91	39.99	4
D-6603	671,220.3	4,062,389.4	299.14	16.99	4
PROCS3	671,208.4	4,062,462.6	300.99	25.00	12
BLD54E	671,280.5	4,062,170.3	299.66	20.01	4
COKER	671,225.6	4,061,567.6	301.84	14.99	10
H-5001	671,214.8	4,061,104.1	305.41	45.01	5
BLD-243	671,240.4	4,061,025.3	304.92	14.99	9
PROCS11	671,261.9	4,061,022.5	304.91	29.99	7
PROCS12	671,312.7	4,061,067.0	305.19	29.99	15
PROCS13	671,272.9	4,061,035.2	304.99	20.01	8
BLD-228	671,294.2	4,061,077.4	305.22	29.99	8
BLD-201	671,318.7	4,061,137.5	305.98	14.99	8
DRUMS1	671,308.2	4,060,982.8	304.69	14.99	4
BLD-260	671,355.2	4,060,985.0	304.80	12.01	4
FIREPH	671,366.2	4,060,979.4	305.04	14.99	4
EPLRM	671,197.2	4,062,634.1	300.70	14.99	4
BLD-328	671,158.0	4,062,596.3	304.08	29.99	6
4FCCCRRM	671,218.3	4,062,435.0	300.27	25.00	4

ID	Easting	Northing	Elevation	Height	Corners
	meters	meters	meters	feet	
FANS1	671,112.0	4,062,415.2	301.50	90.00	4
PROCS17	671,117.4	4,062,403.0	301.09	25.00	8
X-6977	671,119.0	4,062,446.9	302.65	70.01	4
D-6944	671,118.3	4,062,453.9	302.69	39.99	4
PROCS18	671,148.4	4,062,433.8	301.23	25.00	16
FANS2	671,190.7	4,062,486.6	301.17	100.00	4
PROCS19	671,184.5	4,062,434.1	300.88	25.00	13
PROCS20	671,139.2	4,062,397.8	300.55	39.99	10
H-6014BH	671,150.7	4,062,401.3	300.83	50.00	4
PROCS21	671,190.8	4,062,393.3	299.73	25.00	4
H-6007BH	671,163.7	4,062,428.4	301.32	50.00	4
T-6027	671,117.1	4,062,322.6	299.52	50.00	5
BLD-160	671,065.8	4,061,792.7	298.75	20.00	4
PROCS23	671,115.8	4,061,737.4	298.20	39.99	4
D-406	671,091.7	4,061,731.1	298.24	20.01	4
Y-3	671,058.5	4,061,748.7	298.74	39.99	4
H-28	671,027.0	4,061,691.5	299.15	50.00	4
H-29	671,027.5	4,061,701.9	299.24	50.00	4
BLD-159	671,052.0	4,061,697.1	299.02	14.99	4
PROCS24	671,083.7	4,061,542.3	299.57	50.00	4
D-156	671,077.8	4,061,498.3	301.03	12.01	4
D-158	671,075.9	4,061,485.2	301.02	12.01	4
D-159	671,076.1	4,061,478.6	301.11	12.01	4
D-160	671,076.8	4,061,472.0	301.37	12.01	4
Y-6CLTW	671,080.5	4,061,376.4	303.59	50.00	4
BLD-28	671,079.5	4,061,456.9	302.09	25.00	5
B-5004	671,146.1	4,061,070.7	305.76	50.00	4
PROCS27	671,204.8	4,061,075.4	305.19	39.99	4
PROCS28	671,186.3	4,061,063.1	305.02	39.99	14
PROCS29	671,203.6	4,061,040.7	305.00	50.00	4
BLD-251	671,161.6	4,061,032.7	305.14	70.01	4
PROCS30	671,202.3	4,061,000.3	304.86	14.99	6
BLD-252	671,174.9	4,060,994.1	304.94	12.01	4
BLD-52	670,880.2	4,061,999.0	305.81	20.00	4
BLD-1-E	670,914.1	4,062,017.8	305.42	35.01	4
BLD-51	670,882.1	4,061,979.0	305.63	50.00	4
PROCS33	670,900.7	4,061,948.7	305.39	40.00	11
H-15BS	670,815.9	4,061,792.2	303.44	25.00	4
PROCS34	670,884.4	4,061,791.8	303.55	50.00	4
PROCS35	670,885.0	4,061,785.2	303.59	10.01	4
PROCS36	670,893.3	4,061,785.0	303.59	25.00	4

ID	Easting	Northing	Elevation	Height	Corners
	meters	meters	meters	feet	
D-806	670,885.1	4,061,784.9	303.59	14.99	4
PROCS37	670,873.3	4,061,784.7	303.60	20.01	4
PROCS38	670,861.1	4,061,864.0	305.01	79.99	4
PROCS39	670,871.6	4,061,860.7	304.95	79.99	4
H-4	670,861.4	4,061,888.8	304.97	40.00	4
H-3	670,880.0	4,061,887.9	305.07	60.00	4
COMPRES	670,931.8	4,061,874.4	304.81	20.01	4
BLD-273	670,979.9	4,061,503.5	300.31	20.01	5
PROCS40	670,998.8	4,061,460.0	300.57	35.01	4
BLD-74	670,968.7	4,061,453.5	300.60	14.99	4
PROCS41	670,977.7	4,061,392.8	300.66	50.00	12
PROCS42	670,978.4	4,061,367.9	300.68	25.00	4
PROCS43	670,978.4	4,061,338.6	300.77	14.99	4
PROCS44	670,978.4	4,061,348.9	300.70	39.99	4
BLD-179	670,987.9	4,061,329.3	300.77	39.99	4
PROCS45	671,010.7	4,061,307.6	301.04	14.99	11
Y-7CLTW	670,765.3	4,061,951.4	303.67	39.99	5
BLD-178	670,712.3	4,062,022.7	303.59	20.01	4
Y-10CLT1	670,620.3	4,061,610.8	301.09	50.00	4
Y-10CLT2	670,624.1	4,061,584.1	301.58	40.00	4
D-237	670,771.3	4,061,740.2	301.52	12.01	4
D-5008	670,782.7	4,061,734.3	301.60	12.01	4
PROCS48	670,780.7	4,061,568.2	301.70	39.99	4
PROCS49	670,747.2	4,061,577.0	301.78	39.99	4
PROPSTRG	670,578.2	4,061,636.5	301.66	14.99	7
PILOTPL	670,422.4	4,062,704.0	303.27	39.99	20
STOWER	670,797.5	4,062,612.3	305.76	200.00	4
NTOWER	670,811.7	4,062,708.0	306.22	200.00	4
CONTBLD	670,811.3	4,062,586.2	306.17	70.01	17
BLD4	670,939.9	4,062,075.6	305.42	35.00	9
BLD6	670,947.2	4,062,218.9	305.67	30.00	13
BLD331	671,129.2	4,062,676.4	305.60	35.00	7
BLD317	671,129.7	4,062,697.9	305.95	40.00	7
HYPDH009	671,215.5	4,062,756.0	304.25	20.00	7

VIII.1.1.4 Meteorological Data

Pre-processed AERMOD ready meteorological input files obtained from Oklahoma (provided on January 18, 2024) were used for the modeling analysis. These files were processed using AERMET (version 23132) with the ADJ_U* option enabled, AERMINUTE (version 15272), and AERSURFACE (version 20060). The dataset incorporated Integrated Surface Hourly (ISH) data

and sub-hourly ASOS data from the Ponca City Municipal Airport (KPNC, Station No. 13969) and upper air data from the OU Max Westheimer Airport (KOUN – Station No. 0348).

VIII.1.1.5 Receptor Grid

The receptor grid used in this analysis reflects Oklahoma DEQ's Current Guidance.[15] Ground-level concentrations are calculated for receptors located on five Cartesian grids covering a region that extends at least 10 kilometers from all facility emission sources. The grid used for the modeling analysis is defined below.

- A fence line grid containing 50 meter-spaced receptors located along the facility fence line.
- A 100-meter grid containing 100 meter-spaced receptors, extending approximately 1.0 kilometer from the fence line, exclusive of the fence line grid.
- A 250-meter grid containing 250 meter-spaced receptors, extending approximately 2.5 kilometers from the fence line, exclusive of the 100-meter grid.
- A 500-meter grid containing 500 meter-spaced receptors, extending approximately 5.0 kilometers from the fence line, exclusive of the 250-meter grid.
- A 750-meter grid containing 750 meter-spaced receptors, extending approximately 7.5 kilometers from the fence line, exclusive of the 500-meter grid.
- A 1,000-meter grid containing 1,000 meter-spaced receptors, extending approximately 10.0 kilometers from the fence line, exclusive of the 750-meter grid.

VIII.1.1.6 Significance Analysis

A significant impact analysis is the first level of modeling performed in a PSD ambient air impacts evaluation. For each applicable pollutant, the analysis must include all increases in stack emissions and quantifiable fugitive emissions resulting only from the project.

In the significance analysis, the emissions of CO from the proposed project were evaluated to determine whether they have the potential for significant impact upon the area surrounding the facility. For deterministic standards established on a "not to be exceeded more than" some number of times per year basis, the highest modeled impacts from the significance analysis are the highest first highest (H1H) concentrations.

The significance analysis determines whether the refinery is required to conduct a full impact analysis for a modeled pollutant and also defines the significant receptors for which such an analysis is required. A significant receptor is defined as any receptor at which the modeled impacts due to the proposed sources are equal to or greater than the associated SIL for each applicable pollutant and averaging period.

Results of the significance analysis are presented in Section VIII.1.3 of this Memorandum. The results demonstrate that impacts for CO are below the applicable SILs; therefore, a full impact analysis is not required. No. further discussion is provided in the Memorandum regarding the methods used to complete a full impact analysis. The applicable CO SILs are shown below.

[15] Air Dispersion Modeling Guidelines for Oklahoma Air Quality Permits, June 2017.

Significant Impact Levels

Pollutant	Averaging Period	Significant Impact Level (SIL) ($\mu g/m^3$)
CO	1-hour	2,000
	8-hour	500

VIII.1.2 Source Data

Modeled emissions increases and source parameters of each modified source are presented below.

ID	Easting	Northing	Elevation	Emission Rate	Stack Height	Stack Temp.	Stack Vel.	Stack Diam.
	meter	meter	meter	lb/hr	feet	°F	feet/sec	feet
4FCC	671,229.3	4,062,453.4	300.51	0.80	174.87	427.73	81.04	4.59
5FCC	671,184.3	4,061,075.4	305.18	39.89	174.87	481.73	46.26	8.53
H0003	670,886.3	4,061,872.4	304.95	0.25	100.07	791.33	12.47	4.92
H0004	670,867.3	4,061,884.4	305.08	0.37	117.13	641.93	23.95	6.23
H0010	670,801.3	4,061,786.4	303.26	0.34	100.07	519.53	18.70	4.59
H0011	670,827.3	4,061,780.4	303.57	0.94	100.07	712.13	15.42	2.95
H0023	671,149.3	4,061,625.4	301.17	0.09	100.07	670.73	68.24	2.95
H0028	671,042.3	4,061,724.4	299.30	0.14	166.01	742.73	75.13	7.55
H8601	670,740.3	4,062,064.4	304.01	0.87	129.92	600.53	20.34	7.87
H9851	670,680.3	4,062,112.4	303.86	0.14	100.07	710.33	32.81	3.94
H9902	670,697.3	4,062,168.4	304.12	0.14	100.07	710.33	32.81	3.94

VIII.1.3 Modeling Results

The results presented below demonstrate that, when modeled using EP's and DEQ's preferred methods and in accordance with the most recently published guidance, emissions from the proposed project at the refinery do not cause or contribute to a modeled violation of the CO NAAQS.

As shown in the table below, modeling results demonstrate the impacts of the CO project emissions increases from the refinery as presented in this modeling analysis are below the applicable Significant Impact Levels (SILs). Therefore, no full impact analysis is required, and the modeling demonstrates compliance with the applicable NAAQS.

Modeled Concentrations

Year	CO 1-Hour ($\mu g/m^3$)	CO 8-Hour ($\mu g/m^3$)
2011	12.563	6.455
2012	13.922	6.241
2013	8.625	6.506

Year	CO 1-Hour ($\mu g/m^3$)	CO 8-Hour ($\mu g/m^3$)
2014	11.928	6.932
2015	9.870	6.408
Maximum Modeled Concentration (1)	**13.922**	**6.932**
Significant Impact Level (SIL)	2,000	500
Full Impact Analysis Required?	**No**	**No**

(1) Highest first high impacts for all pollutants and all averaging periods.

VIII.2 Class I Area Analyses

One of the purposes of the PSD program is "to preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national or regional natural, recreational, scenic, or historical values."[16] Under the PSD provisions, Congress established a land classification scheme for these areas of the country (Class I), specifically including:

1. International parks,
2. National wilderness areas which exceed 5,000 acres in size,
3. National memorial parks which exceed 5,000 acres in size, and
4. National parks which exceed 6,000 acres in size.

The Class I area nearest the refinery is the Wichita Mountains Wildlife Refuge in southwestern Oklahoma, which is approximately 250 kilometers southwest of the refinery. Class I area analyses, when conducted, typically include a Class I PSD Increment Assessment for NO_X, SO_2, and PM_{10}, as well as an Air Quality Related Values (AQRV assessment, for increases in visibility impairing pollutants and a deposition analysis for nitrogen and sulfur. The proposed project is not expected to result in emissions of any of these pollutants that exceed the respective SER. As such, no Class I area analysis is required.

VIII.3 Additional Impacts Analyses

VIII.3.1 Growth Impacts

The purpose of the growth analysis is to predict quantitatively the amount of new growth likely to occur to support the source or modification under review and to estimate the emissions that will result from the associated growth. First, an assessment is made regarding the amount of residential growth the modified source will bring to the area. This depends on the size of the available workforce, the number of new employees, and the availability of housing in the area. Associated commercial and industrial growth consists of new sources providing goods and services to the new employees and to the modified source itself. Once these anticipated growth effects have been considered, an estimate of the air pollutant emissions that would likely result from the associated growth is made.

[16] 42 U.S.C. § 7470 (2)

The proposed project is not expected to result in any net additional labor on a permanent basis. Furthermore, no major secondary industry growth is expected to result from the proposed project. Thus, any air quality impact resulting from industrial, commercial, and residential growth in the local area due to the proposed project is expected to be negligible.

VIII.3.2 Soils and Vegetation

The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than 1 month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism, whereas long-term effects may be indirectly caused by secondary agents such as changes in soil pH.

At the levels of CO that occur in urban air, there are no detrimental effects on materials or plants. However, human health may be adversely affected at such levels. The secondary NAAQS were established at concentration levels below which no harmful effects to either soil or vegetation are expected. As demonstrated previously, the modeled impact of the project related CO emissions are less than the Significant Impact Levels (SILs) and will have no adverse impact on the NAAQS. Thus, it can be concluded that any impacts on soil and vegetation will be negligible and are therefore not expected to adversely impact human health.

VIII.3.3 Visibility Impairment

This project is not expected to produce any perceptible visibility impacts in the immediate vicinity of the refinery. Given the limitation of 20% opacity for operations at the refinery, no immediate visibility impairment is anticipated.

SECTION IX. EQUIPMENT

Emission units (EUs) have been arranged into Emission Unit Groups (EUGs) as shown below. EUs with no applicable federal or state standards, recordkeeping, or reporting requirements are not included in the TV permit.

TANKS

EUG TNK-1: Storage Vessels Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) and 40 CFR Part 63 Subpart WW

EUG TNK-2: Storage Vessels Subject to 40 CFR Part 60 Subpart Kb and 40 CFR Part 63 Subpart CC (MACT I)

EUG TNK-3: Storage Vessels Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) Recordkeeping

EUG TNK-4: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 1 Wastewater Streams Handled by Either Tanks or Storage Vessels
EUG TNK-5: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 2 Wastewater Streams Handled by Storage Tanks
EUG TNK-6: 40 CFR Part 63 Subpart EEEE (OLD MACT) Fixed Roof Storage Tanks
EUG TNK-7: Storage Tanks Subject to Oklahoma Rules or Permit Requirements
EUG TNK-8: Insignificant Activity Storage Tanks

HEATERS & BOILERS

EUG HTR-1: 40 CFR Part 60 Subparts J, Db, & Dc and 40 CFR Part 63 Subpart DDDDD Boilers
EUG HTR-2: 40 CFR Part 60 Subpart J and 40 CFR Part 63 Subpart DDDDD Heaters & Boilers
EUG HTR-2.1: 40 CFR Part 60 Subpart Ja and 40 CFR Part 63 Subpart DDDDD Heaters & Boilers
EUG HTR-2.2: Boilers Subject to 40 CFR Part 63 Subpart DDDDD
EUG HTR-3: Heaters & Boilers Subject to Oklahoma Rules or Permit Limits
EUG HTR-4: Insignificant Activity Heaters & Boilers

MISCELLANEOUS

EUG ENG: Engines
EUG ENG-1a: Existing 2SLB Engines >500-hp "Subject" to 40 CFR Part 63 Subpart ZZZZ (RICE MACT) but with No Emission Limitations or Operating Requirements
EUG ENG-1b: Existing Emergency Engines >500-hp "Subject" to 40 CFR Part 63 Subpart ZZZZ but with No Emission Limitations or Operating Requirements
EUG ENG-2: CI Emergency Engines 500-hp or Less Subject to 40 CFR Part 63 Subpart ZZZZ (RICE MACT) Table 2c Requirements
EUG ENG-3: 4SLB Non-Emergency Engines <100-hp Subject to 40 CFR Part 63 Subpart ZZZZ (RICE MACT) Table 2c Requirements
EUG ENG-4: Emergency CI Engines Subject to 40 CFR Part 60 Subpart IIII
EUG ENG-5: Non-Emergency CI Engines Subject to 40 CFR Part 60 Subpart IIII
EUG FCC-1: Fluid Catalytic Cracking Unit Catalyst Regenerators Subject to 40 CFR Part 60, Subpart J and 40 CFR Part 63 Subpart UUU (Refinery MACT II)
EUG FCC-2: Fluid Catalytic Cracking Unit Catalyst Regenerators Subject to 40 CFR Part 60 Subpart Ja and 40 CFR Part 63 Subpart UUU (Refinery MACT II)
EUG CRU-1: Catalytic Reforming Unit Catalyst Regenerator Vents Subject to 40 CFR Part 63 Subpart UUU (Refinery MACT II)
EUG FLR-1: Flares Subject to 40 CFR Part 60 Subpart Ja
EUG LOD-1: Reserved
EUG LOD-2: Loading Racks Subject to Oklahoma Rules or Permit Requirements
EUG LOD-3: Insignificant Activity Loading Racks
EUG VNT-1: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 1 Miscellaneous Process Vents
EUG VNT-2: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 2 Miscellaneous Process Vents

EUG VNT-3: Reserved
EUG VNT-4: 40 CFR Part 63 Subpart GGGGG (Site Remediation MACT) Process Vents
EUG VNT-5: Insignificant Activity Atmospheric Process Vents
ENG VNT-6: Equipment Subject to the Maintenance Vent Provisions of 40 CFR Part 63 Subpart CC (Refinery MACT I)

FUGITIVE EMISSION EQUIPMENT

EUG FUG-1: Fugitive Equipment Leaks Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) and/or 40 CFR Part 60 Subpart GGGa
EUG FUG-2: Fugitive Oily Water Sewer System Component Leaks Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) and 40 CFR Part 61 Subpart FF (Benzene Waste Operations)
EUG FUG-3: Fugitive Oily Water Sewer System Component Leaks Subject to 40 CFR Part 60 Subpart QQQ
EUG FUG-4: Fugitive Oily Water Sewer System Component Leaks Subject to 40 CFR Part 61 Subpart FF (Benzene Waste Operations) Exemption Recordkeeping Requirements
EUG FUG-5: Reserved
EUG FUG-6: Cooling Tower Fugitive Sources Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I)
EUG FUG-6.1 Insignificant Cooling Tower Fugitive Sources
EUG FUG-7: Materials Handling Fugitive Sources Subject to Oklahoma Rules or Permit Requirements
EUG FUG-8: Insignificant Activity Fugitive Sources
EUG COK-1: Delayed Cokers Subject to 40 CFR Part 60 Subpart Ja and 40 CFR Part 63 Subpart CC

FACILITY-WIDE

EUG FW: Facility-Wide Applicable Requirements

IX.1 TANKS

Tank contents will vary depending upon refinery requirements but will be limited by the suitability of a particular tank for a particular hydrocarbon. Roof types noted are external floating roof (EFR), internal floating roof (IFR), vertical fixed roof (VFR), horizontal fixed roof (HFR), and open top (OT). There are also several spherical pressurize vessels on-site without emissions to the atmosphere; however, they will not be specifically identified in the tables below. The capacities listed represent the physical tank volumes using the internal cross-sectional area and tank shell heights (not taking into consideration safe fill levels).

EUG TNK-1: Storage Vessels Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) and 40 CFR Part 63 Subpart WW

EU ID	Point ID	Normal Contents	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date
T-0021E	T-0021E	Naphtha	3,348,342	EFR	1954
T-0101	Permanently removed from service and replaced by tank T-0102 in 2017.				
T-0114	T-0114	Gasoline	439,433	IFR	1919
T-0148	T-0148	Gasoline	3,377,633	IFR	1923
T-0149	T-0149	Gasoline	3,377,633	IFR	1923
T-0150	T-0150	Gasoline	3,377,633	IFR	1923
T-0151	T-0151	Gasoline	3,377,633	IFR	1923
T-0154	T-0154	Reformate	6,344,761	EFR	1977
T-0155	T-0155	Gasoline	3,377,633	IFR	1923
T-0158	T-0158	Gasoline	3,351,095	IFR	1924
T-0159	T-0159	Gasoline	3,391,305	IFR	1923
T-0160	T-0160	Gasoline	3,343,857	IFR	1924
T-0163	T-0163	LSR Gasoline	3,330,990	IFR	1924
T-0164	T-0164	LSR Gasoline	3,351,095	IFR	1924
T-0167	T-0167	Gasoline	1,363,316	IFR	1976
T-0170	T-0170	Gasoline	1,078,341	IFR	1920
T-0901	T-0901	Gasoline	3,330,990	IFR	1924
T-0902	T-0902	Naphtha	3,357,528	IFR	1971
T-0953	T-0953	Gasoline	2,339,924	IFR	1944

EUG TNK-2: Storage Vessels Subject to 40 CFR Part 60 Subpart Kb and 40 CFR Part 63 Subpart CC (Refinery MACT I)

EU ID	Point ID	Normal Contents	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date
T-0014E	T-0014E	Naphtha	258,678	EFR	1995
T-0015	T-0015	Naphtha	541,420	EFR	1995
T-0017E	T-0017E	Crude Oil	485,310	EFR	1987
T-0117	T-0117	Naphtha	9,340,615	EFR	1990
T-0119	T-0119	Naphtha	9,340,615	EFR	1990
T-0121	T-0121	Diesel	4,964,188	IFR	2005
T-0141	T-0141	Slop Oil	30,455	EFR	1990
T-0147	T-0147	Naphtha	3,383,872	EFR	1989
T-0153	T-0153	Reformate	3,360,000	IFR	2019
T-0156	T-0156	Gasoline	3,826,376	EFR	1993

EU ID	Point ID	Normal Contents	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date
T-0162	T-0162	Gasoline	3,310,860	IFR	1924/2011
T-0165	T-0165	Alkylate	3,405,021	EFR	1991
T-0166	T-0166	Gasoline	4,060,647	EFR	1991
T-0176	T-0176	Toluene	1,355,859	IFR	1988
T-0177	T-0177	Toluene	116,512	IFR	1988
T-0178	T-0178	Aviation Gasoline	454,087	IFR	1988
T-0357	T-0357	Slop Oil	8,812	EFR	1993
T-0402	T-0402	Slop Oil	11,844	EFR	1993
T-0540	T-0540	Methanol	170,040	IFR	1987
T-0690	T-0690	Slop Oil	13,324	EFR	1992
T-0944	T-0944	Sour Water	1,043,961	IFR	1944 / Recon-structed 2012

EUG TNK-3 Storage Vessels Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) Recordkeeping

EU ID	Point ID	Normal Contents	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date
D-0924	D-0924	MDEA	27,900	HFR	2004
T-0003	T-0003	Dye	48,661	VFR	Post-1984
T-0038	T-0038	Crude Oil	424,453	EFR	1950
T-0064	T-0064	Diesel	369,089	VFR	1926
T-0070	T-0070	Spent Caustic	425,921	VFR	1921
T-0077	T-0077	Spent Caustic	215,898	VFR	1921
T-0102	T-0102	Diesel	1,050,000	VFR	2017
T-0106E	T-0106E	Gas Oil	1,143,749	VFR	1991
T-0107E	T-0107E	Gas Oil	1,143,749	VFR	1990
T-0120	T-0120	Gas Oil	11,088,636	VFR	1990
T-0123	T-0123	Diesel	3,684,661	VFR	1992
T-0124	T-0124	Diesel	3,684,661	VFR	1992
T-0125	T-0125	Diesel	3,684,661	VFR	1992
T-0126	T-0126	Diesel	3,684,661	VFR	1992
T-0128	T-0128	Jet Fuel	3,619,157	VFR	1992
T-0129	T-0129	Diesel	3,619,157	VFR	1992
T-0130	T-0130	Diesel	6,831,266	VFR	1992
T-0131	T-0131	Diesel	6,831,266	VFR	1992
T-0135	T-0135	Diesel	4,586,000	VFR	1992
T-0136	T-0136	Diesel	4,586,000	VFR	1992
T-0142	T-0142	Residuum	3,398,254	VFR	1989

EU ID	Point ID	Normal Contents	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date
T-0143	T-0143	Residuum	6,644,304	VFR	1990
T-0144	T-0144	Residuum	6,644,304	VFR	1991
T-0152	T-0152	Gas Oil	3,377,640	EFR	1974/2011
T-0161	T-0161	Gas Oil	3,363,962	VFR	1974
T-0168	T-0168	Jet Fuel	424,453	VFR	1950
T-0169	T-0169	Jet Fuel	424,453	VFR	1950
T-0171	T-0171	Vendor Chemical	20,000	VFR	1943
T-0179	T-0179	Jet Fuel	46,998	VFR	1988
T-0253	T-0253	Spent Caustic/HC	31,724	VFR	1994
T-0254(1)	T-0254	Spent Caustic/HC	13,535	VFR	1994
T-0509(1)	T-0509		43,453	VFR	1968
T-0260	T-0260	Caustic/HC	26,437	VFR	1987
T-0500	T-0500	Gas Oil	2,819,894	VFR	1983
T-0501	T-0501	Coker Fines Water/HC	214,140	OT	1990/2019
T-0536	T-0536	Seal Oil	16,919	VFR	1983
T-0561	T-0561	Hydrocarbon	26,418	VFR	1971
T-0633	T-0633	Jet Fuel	3,383,872	VFR	1985
T-0636	T-0636	Jet Fuel	3,349,806	VFR	1929
T-0639	T-0639	Jet Fuel	2,285,600	VFR	1926/2011
T-0904	T-0904	Gas Oil	3,317,318	VFR	1924
T-0905	T-0905	Gas Oil	3,317,318	VFR	1924/2009
T-0906	T-0906	Gas Oil	1,047,993	VFR	1944
T-0913	T-0913	Gas Oil	1,050,262	VFR	1943
T-0914	T-0914	Gas Oil	1,054,295	VFR	1943
T-0916	T-0916	Gas Oil	66,091	VFR	1944
T-0970	T-0970	Residuum	1,903,428	VFR	2000
T-0971	T-0971	Residuum	1,903,428	VFR	2000
T-0972	T-0972	Residuum	1,903,428	VFR	2000

1. These two tanks are operated in parallel, essentially as a single storage vessel.

EUG TNK-4: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 1 Wastewater Streams Handled by Either Tanks or Storage Vessels

EU ID	Point ID	Normal Contents	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date
D-0777	D-0777	Wastewater	564	HFR	Pre-1991
D-0779	D-0779	Wastewater	10,403	HFR	Pre-1991
D-5292	D-5292	Spent Caustic/HC	1,900	HFR	1943
T-0037	T-0037	Slop Oil	586,200	EFR	1993
T-0201	T-0201	Slop Oil	490,573	EFR	1991

EU ID	Point ID	Normal Contents	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date
T-0202	T-0202	Slop Oil	490,573	EFR	1991
T-0203	T-0203	Slop Oil	21,995	IFR	1991
T-0204	T-0204	Wastewater	490,573	EFR	1991
T-0205	T-0205	Wastewater	490,573	EFR	1991
T-0551	T-0551	Wastewater	490,573	EFR	1991
T-0552	T-0552	Wastewater	490,573	EFR	1992
T-0553	T-0553	Slop Oil	256,651	EFR	1991
T-0554	T-0554	Slop Oil	256,651	EFR	1992
T-0555	T-0555	Slop Oil	21,995	IFR	1993
T-0651	T-0651	Wastewater	3,363,962	VFR	1923
T-0652	T-0652	Wastewater	3,377,423	VFR	1923
T-0654	T-0654	Wastewater	3,077,933	EFR	1923
T-0665	T-0665	Wastewater	3,752,617	EFR	1991
T-0667	T-0667	Slop Oil	21,995	IFR	1991
T-0669	T-0669	Spent Caustic/HC	270,401	EFR	1991
T-0701	T-0701	Slop Oil	256,651	EFR	1991
T-0702	T-0702	Slop Oil	256,651	EFR	1991
T-0703	T-0703	Slop Oil	22,068	IFR	1991
T-0704	T-0704	Wastewater	270,401	EFR	1991
T-0705	T-0705	Wastewater	270,401	EFR	1991
T-0706	T-0706	Wastewater	270,401	EFR	1991
T-0907	T-0907	Sour Water	1,056,563	IFR	1943
T-0908	T-0908	Sour Water	1,052,278	IFR	1943
T-0910	T-0910	Slop Oil	663,215	IFR	1943

D-0777, D-0779, D-5292, T-0651, and T-0652 were or are currently in MACT Group 2 wastewater service. However, the vessels can be operated with carbon canister controls such that they could store a Group 1 material, and the facility prefers to list the tanks with Group 1 wastewater tanks.

EUG TNK-5: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 2 Wastewater Streams Handled by Storage Tanks

EU ID	Point ID	Normal Contents	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date
D-0232	D-0232	Wastewater	924	HFR	1989
D-0775	D-0775	Wastewater	10,300	HFR	1990
D-0776	D-0776	Wastewater	10,300	HFR	1990
D-0780	D-0780	Wastewater	10,403	HFR	1990
D-0783	D-0783	Wastewater	3,475	HFR	1990

EU ID	Point ID	Normal Contents	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date
D-0786-1	D-0786-1	Wastewater	564	HFR	Est. 1990
D-6801	D-6801	Wastewater	5,000	VFR	1964
D-6812	D-6812	Wastewater	16,044	HFR	1991
T-0080	T-0080	Slop Oil	105,000	VFR	1941
T-0140	T-0140	Wastewater	4,053	VFR	1990
T-0173	T-0173	Brine Water/HC	5,558	VFR	1992
T-0648	T-0648	Wastewater	4,576	VFR	1992
T-0680	T-0680	ASU Lift Station Overflow	250,000	OT	1993
T-0966	T-0966	Slop Oil	14,161	VFR	1945
T-0973	T-0973	Spent Caustic/HC	213,523	VFR	1960

EUG TNK-6: 40 CFR Part 63 Subpart EEEE (OLD MACT) Fixed Roof Storage Tanks

The facility is an existing source for the purposes of 40 CFR Part 63 Subpart EEEE. The compliance date for existing sources was February 5, 2007.

EU ID	Point ID	Normal Contents	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date
T-0017	T-0017	Perchloroethylene	350	VFR	1994
T-0018	T-0018	Perchloroethylene	550	VFR	1994
T-0027	T-0027	Methanol	550	VFR	2006
T-0057	T-0057	Methanol	550	VFR	2005
T-0058	T-0058	Methanol	550	VFR	2005
T-0104	T-0104	Methanol	1,680	VFR	1922
T-0212 E	T-0212 E	Vendor Chemical	564	VFR	1971
T-0230	T-0230	Glycol Water	4,230	VFR	Pre-2004
T-0527	T-0527	Methanol	550	VFR	2006
T-0528	T-0528	Methanol	550	VFR	2007
T-0529	T-0529	Methanol	550	VFR	2007
T-0542	T-0542	Methanol	550	VFR	Pre-2000
T-0111	T-0111	Methanol	550	VFR	2007
T-0511	T-0511	Methanol	550	VFR	2010
T-0538	T-0538	Methanol	550	VFR	2011
T-0540 TOTE	T-0540 TOTE	Methanol	550	VFR	2010
T-0543	T-0543	Methanol	550	VFR	2010
T-2254	T-2254	Methanol	550	VFR	2011
T-5005	T-5005	Methanol	550	VFR	2011
T-9403	T-9403	Methanol	550	VFR	2012

EU ID	Point ID	Normal Contents	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date
NP Methanol Tote	NP Methanol Tote	Methanol	350	VFR	2010
TNK-Misc. Vendor Totes/Tanks	TNK-Misc. Vendor Totes/Tanks	Vendor Chemical	< 5,000	VFR	2007

EUG TNK-7: Storage Tanks Subject to Oklahoma Rules or Permit Requirements

EU ID	Point ID	Normal Contents	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date
T-0024	T-0024	Gasoline	2,016	VFR	1986
TNK-MP Gasoline	TNK-MP Gasoline	Gasoline	1,000	VFR	2002
TNK-GFMHL #1	TNK-GFMHL #1	Gasoline	500	HFR	2017
TNK-GFMRW #1	TNK-GFMRW #1	Gasoline	500	HFR	2000
TNK-GFMNT1	TNK-GFMNT1	Wastewater	18,411	IFR	1993

EUG TNK-8: Insignificant Activity Storage Tanks

EU ID	Point ID	Normal Contents	Insignificant Activity Reason (1)
T-0008	T-0008	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0006 E	T-0006 E	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0012	T-0012	Jet Water Pump Surge, Fines Filtering	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0014	T-0014	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0023	T-0023	Diesel Storage at Fuel Pump	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0031	T-0031	Spent Naphthenic Caustic	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0157	T-0157	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia

EU ID	Point ID	Normal Contents	Insignificant Activity Reason (1)
T-0534	T-0534	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0535	T-0535	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0603	T-0603	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0604	T-0604	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
TNK-Fire Training #1	TNK-Fire Training #1	Kerosene storage at Fire Training Grounds	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
TNK-GFMHL #2	TNK-GFMHL #2	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
TNK-GFMST	TNK-GFMST	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
TNK-Misc. Vendor Totes / Tanks	TNK-Misc. Vendor Totes / Tanks	Vendor chemicals with TVP < 1.0 psia and containing < 4% RM1 HAPs, < 5% OLD MACT HAPs, or inorganic	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
TNK-MP Diesel	TNK-MP Diesel	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
TNK-GFMRW #2	TNK-GFMRW #2	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
TNK-Misc. Lube Oil Reservoirs	TNK-Misc. Lube Oil Reservoirs	Lube oil	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia

1. Tanks that are insignificant due to emissions being less than 5 TPY require recordkeeping.

IX.2 HEATERS & BOILERS

EUG HTR-1: 40 CFR Part 60 Subparts J, Db, & Dc and 40 CFR Part 63 Subpart DDDDD Boilers

EU ID	Point ID	Equipment	Fired Duty MMBtu/hr	Construction/ Modification Date
B-0008	B-0008 (SC 33)	Steam Boiler	483	2003
B-0009/0010	B-0009/0010 (SC 33)	Steam Boiler	734 (1)	2005
B-0021	Permanently removed from service by June 2012 and shall not be returned to service.			

EU ID	Point ID	Equipment	Fired Duty MMBtu/hr	Construction/ Modification Date
B-0022	B-0022 (SC 33)	Steam Boiler	95	2009

1. The boilers share a common stack. The fired duty shown is a total for both boilers.

EUG HTR-2: 40 CFR Part 60 Subpart J and 40 CFR Part 63 Subpart DDDDD Heaters & Boilers

Consent Decree No. H-01-4430 required all of the facility's heaters and boilers that combust refinery fuel gas to be subject to Subpart J, regardless of the construction or modification date. The requirements of this Consent Decree have been incorporated into the specific conditions of the permit.

EU ID	Point ID	Equipment	Fired Duty MMBtu/hr	Construction/ Modification Date
B-0006	Permanently removed from service by July 31, 2009 and shall not be returned to service.			
B-0007				
B-5004	Permanently removed from service by December 31, 2022 and shall not be returned to service.			
H-0001	Permanently removed from service by September 24, 2017 and shall not be returned to service			
H-0003	H-0003	No. 4 CVU Feed Heater	32.0	1929/2002 (1,2,3)
H-0004	H-0004	No. 4 CTU Feed Heater	118	1945/2002 (1,2,3)
H-0005	Permanently removed from service by September 24, 2017 and shall not be returned to service.			
H-0010	H-0010	Saturate Gas Plant Naphtha Reboiler	55.0	1972(2)
H-0011	H-0011	No. 7 HDT Heater	18	1988
H-0016	H-0016	No. 1 CVU Feed Heater	107	2004(2)
H-0023	H-0023	No. 5 HDT Heater	52.4	1984(2)
H-0028	H-0028/0029	No. 7 Coker Heater	129	1954
H-0029	H-0028/0029	No. 7 Coker Heater	75.0	1983(2)
H-0046	H-0046	No. 2 HDS Feed Heater	48.0	1964
H-0048	H-0048	No. 2 CRU Heater	241.4	1957
H-0057	Permanently removed from service by February 28, 2009 and shall not be returned to service.			
H-0058				
H-0059				
H-1001	H-1001	No. 4 HDT Heater	30.0	2005
H-5001	Permanently removed from service by December 18, 2008 and shall not be returned to service.			
H-6005	H-6005	No. 2 CTU Preflash Reboiler Heater	170	1997(2)
H-6007	H-6007	No. 3 CRU Heater	150	1956 / 1990 (1,2)
H-6008	H-6008	Butane Dryers Regenerator Heater	2.0	1955

EU ID	Point ID	Equipment	Fired Duty MMBtu/hr	Construction/ Modification Date
H-6012	H-6012	No. 3 HDS Heater	25.0	1971
H-6013	H-6013	No. 3 CRU Heater	75.8	2002(2)
H-6014	H-6014	No. 2 CVU Feed Heater	72.0	1978(2)
H-6015	H-6015	No. 2 CTU Feed Heater	79.0	1980(2)
H-6151	H-6151	No. 4 FCCU Feed Preheater	80.0	1958
H-7501	H-7501	No. 6 HDT Heater	36.6	1991
H-8601	H-8601	No. 8 HDT Splitter Reboiler Heater	120	2003 (Pre-12/13/03) (2)
H-8602	H-8602	No. 8 HDT Heater	36.0	2003 (Pre-12/13/03)
H-8801/8802	H-8801/8802	No. 1 Hydrogen Plant Reformer Heater	123	2003 (Pre-12/13/03) (2)
H-9851	H-9851	No. 2 Hydrogen Plant Reformer Heater	282	2005(2)
H-9901	H-9901	No. 9 HDT Heater	40.0	2005
H-9902	H-9902	No. 9 HDT Stripper Reboiler Heater	50.0	2005(2)

1. Subchapter 31 modification.
2. Subchapter 33 modification.
3. NSPS modification or reconstruction.

EUG HTR-2.1: 40 CFR Part 60 Subpart Ja and 40 CFR Part 63 Subpart DDDDD Heaters & Boilers

EU ID	Point ID	Equipment	Fired Duty MMBtu/hr	Construction/ Modification Date
H-0001	H-0001	No. 1 CTU Atm Tower Feed Heater	275	2017(1)
H-5002 (2)	H-5002	No. 5 FCCU Feed Preheater	120	2008(1)
H-9301	H-9301	Benzene Fractionation Unit Process Heater	131	2010
H-0060 (1)	H-0060	Alky Depropanizer Heater	147	2008(3)

1. Authorized under 98-104-C (M-15).
2. Replaced H-5001.
3. Subchapter 33 modification

EUG HTR-2.2 Boilers Subject to 40 CFR Part 63 Subpart DDDDD

EU ID	Point ID	Equipment	Fired Duty MMBtu/hr	Construction/ Modification Date
BLR-GFMRW1	BLR-GFMRW1	Research West Boiler #1	20.9	11/13/1978(1)
BLR-GFMRW3	BLR-GFMRW3	Research West Boiler #3	20.9	11/13/1978(1)
BLR-GFMRW4	BLR-GFMRW4	Research West Boiler #4	14.6	2/25/1982(1)
BLR-GFMRW5	BLR-GFMRW5	Research West Boiler #5	14.6	2/25/1982(1)
BLR-GFMRW6	BLR-GFMRW6	Research West Boiler #6	14.6	2/25/1982(1)

1. Subchapter 33 modification

EUG HTR-3: Heaters & Boilers Subject to Oklahoma Rules or Permit Limits

EU ID	Point ID	Equipment	Fired Duty MMBtu/hr	Construction/ Modification Date
H-6037A/ 6037B	No. 4 FCCU	No. 4 FCCU Startup Preheater	23.4	1988
HTR-5FCC Converter Air Preheater	No. 5 FCCU	No. 5 FCCU Converter Startup Preheater	Est. >10 but <50	1971

EUG HTR-4: Insignificant Activity Heaters & Boilers

EU ID	Point ID	Equipment	Insignificant Activity Reason
BLR-GFMNT1	BLR-GFMNT1	North Tower Emergency Boiler	App. I: Combustion Equipment-Commercial Nat. Gas < 5 MMBtu/hr
BLR-GFMPB1	BLR-GFMPB1	Park Bldg Boiler #1	App. I: Combustion Equipment-Commercial Nat. Gas < 5 MMBtu/hr
BLR-GFMPB2	BLR-GFMPB2	Park Bldg Boiler #2	App. I: Combustion Equipment-Commercial Nat. Gas < 5 MMBtu/hr
BLR-GFMST1	BLR-GFMST1	South Tower Emergency Boiler [Diesel Fired]	App. I: Activities having the potential to emit no more than 5 TPY [actual] of any pollutant.

IX.3 MISCELLANEOUS

EUG ENG

This emission unit group encompasses all engines at the facility, which are further divided into the following emissions unit groups.

EUG ENG-1a: Existing 2SLB Engines >500-hp "Subject" to 40 CFR Part 63 Subpart ZZZZ (RICE MACT) but with No Emission Limitations or Operating Requirements

EU ID	Point ID	Equipment	Horse power	Construction/ Modification Date
E-0068	E-0068	Sat Gas Unit Engine	550	1950's
E-0072	E-0072	Sat Gas Unit Engine	600	1941

EUG ENG-1b: Existing Emergency Engines >500-hp "Subject" to 40 CFR Part 63 Subpart ZZZZ (RICE MACT) but With No Emission Limitations or Operating Requirements

EU ID	Point ID	Equipment	Horse power	Construction/ Modification Date
ENG-GFMPB	ENG-GFMPB	Park Building Generator Engine for Emergency Backup Power	732	2004

EUG ENG-2: CI Emergency Engines 500-hp or Less Subject to 40 CFR Part 63 Subpart ZZZZ (RICE MACT) Table 2c Requirements

EU ID	Point ID	Equipment	Horse power	Construction/ Modification Date
E-0003	E-0003	North Plant Fire Water Pump Engine	482	12/8/2004
E-0004	E-0004	North Plant Fire Water Pump Engine	482	11/24/2004
E-0061	E-0061	East Plant Fire Water Pump Engine	375	10/20/1993
E-0062	E0062	East Plant Fire Water Pump Engine	375	11/16/1993
E-0158	Permanently removed from service by August 31, 2018, and shall not be returned to service			
E-ALKY	E-ALKY	HF Alky Backup Power Generator Engine	58	[Prior to 7/11/2005]

EU ID	Point ID	Equipment	Horse power	Construction/ Modification Date
E-GFMCB	E-GFMCB	Continental Building Backup Power Generator Engine	207	[Prior to 7/11/2005]
E-GFMSB	E-GFMSB	Security Building Backup Power Generator Engine	207	6/30/2003
E-GFMST	E-GFMST	South Tower Backup Power Generator Engine	150	[Prior to 7/11/2005]

EUG ENG-3: 4SLB Non-Emergency Engines <100-hp Subject to 40 CFR Part 63 Subpart ZZZZ (RICE MACT) Table 2c Requirements

EU ID	Point ID	Equipment	Horse power	Construction/ Modification Date
E-0075	E-0075	Gasoline Knock Test Engine	4	1969
E-0104	E-0104		4	1975
E-0106	E-0106		4	1975
E-LABB	E-LABB		4	1972

EUG ENG-4: Emergency CI Engines Subject to 40 CFR Part 60 Subpart IIII

EU ID	Point ID	Equipment	HP	Displace-ment (L/cylinder)	Construction/ Modification Date
ENG-GFMMB	ENG-GFMMB	Microwave Building Generator for Emergency Backup Power	135	<10	Mfr'd 9/2006
ENG-E5017	ENG-E5017	SP Firewater Pump Engine	484	<30	Mfr'd 2007
ENG-E5018	ENG-E5018	SP Firewater Pump Engine	484	<30	Mfr'd 2007
ENG-EPIAB	ENG-EPIAB	East Plant Instrument Air Backup Compressor Engine	200	<30	4/20/2011
E-0118	E-0118	West Plant Fire Water Pump Engine	600	<10	Mfr'd 8/3/2017 Installed 2018
E-SPIAB	E-SPIAB	South Plant Backup Instrument Air Compressor Engine	575	<10	Mfr'd 3/20/2014 Installed 2018

EU ID	Point ID	Equipment	HP	Displace-ment (L/cylinder)	Construction/ Modification Date
E-37	E-37	Research West Backup Power Generator Engine	755	<10	Mfr'd 2018 Installed 10/2018

EUG ENG-5: Non-Emergency CI Engines Subject to 40 CFR Part 60 Subpart IIII

EU ID	Point ID	Equipment	HP	Displace-ment (L/cylinder)	Construction/ Modification Date
ENG-4FCCAB	ENG-4FCCAB	FCC Supplemental Air Blower Compressor Engine	140	<10	5/4/2011
ENG-4FCCCAT	ENG-4FCCCAT	FCC Catalyst Loading Air Compressor Engine	140	<10	6/14/2011

EUG FCC-1: Fluid Catalytic Cracking Unit Catalyst Regenerators Subject to 40 CFR Part 60 Subpart J and 40 CFR Part 63 Subpart UUU (Refinery MACT II)

EU ID	Point ID	Equipment	Construction/ Modification Date
No. 5 FCCU	No. 5 FCCU	No. 5 Fluid Catalytic Cracking Unit	1952 / 1972 (SC 35 mod) / 2023

EUG FCC-2: Fluid Catalytic Cracking Unit Catalyst Regenerators Subject to 40 CFR Part 60 Subpart Ja and 40 CFR Part 63 Subpart UUU (Refinery MACT II)

EU ID	Point ID	Equipment	Construction/ Modification Date
No. 4 FCCU	No. 4 FCCU	No. 4 Fluidized Bed Catalytic Cracking Unit Catalyst Regenerator	1951/2021
No. 5 FCCU	No. 5 FCCU	No. 5 Fluidized Bed Catalytic Cracking Unit Catalyst Regenerator	1952 / 1972 (SC 35 mod) / 2023

EUG CRU-1: Catalytic Reforming Unit Catalyst Regenerator Vents Subject to 40 CFR Part 63 Subpart UUU (Refinery MACT II)

EU ID	Point ID	Equipment	Construction/ Modification Date
No. 2 CRU	No. 2 CRU	No. 2 Catalytic Reforming Unit Catalyst Regenerator Vent	1957

EU ID	Point ID	Equipment	Construction/ Modification Date
No. 3 CRU	No. 3 CRU	No. 3 Catalytic Reforming Unit Catalyst Regenerator Vent	1956

EUG FLR-1: Flares Subject to 40 CFR Part 60 Subpart Ja

EU ID	Point ID	Equipment	Construction/ Modification Date
Flare-CC	Flare-CC	Coker/Combo Alky Flare	1970
Flare-CF	Flare-CF	Clean Fuels and West Plant Flare	2003
Flare-EP	Flare-EP	East Plant Flare	1990
Flare-SP	Flare-SP	South Plant Flare	1972
Flare-Temp	Flare-Temp	Temporary Flare	1994

EUG LOD-1: Reserved

EUG LOD-2: Loading Racks Subject to Oklahoma Rules or Permit Requirements

EU ID	Point ID	Equipment	Construction/ Modification Date
Load-SP	Load-SP	South Plant Loading Rack (Distillates)	Est. 1930's

EUG LOD-3: Insignificant Activity Loading Racks

EU ID	Point ID	Equipment	Insignificant Activity Reason
Load-Refuel#1	Load-Refuel#1	Refinery Vehicle Refueling	App. I: Miscellaneous - < 5 TPY
Load-Refuel#2	Load-Refuel#2	Motor Pool Vehicle Refueling	App. I: Miscellaneous - < 5 TPY
Load-SF	Load-SF	Santa Fe Loading Rack (Distillates)	App. I: Miscellaneous - < 5 TPY
Load-Resid	Load-Resid	Resid Truck Loading Rack	App. I: Miscellaneous - < 5 TPY

EUG VNT-1: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 1 Miscellaneous Process Vents

EU ID	Point ID	Equipment	Construction/ Modification Date
VNT-D0749	Flare-CC	D-749 Merox disulfide separator drum	2001

EUG VNT-2: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 2 Miscellaneous Process Vents

EU ID	Point ID	Equipment	Construction/ Modification Date
VNT-D0701	VNT-D0701	D-701 vent/drain	1970
VNT-D0702	VNT-D0702	D-702 vent/drain	1970
VNT-D0704	VNT-D0704	D-704 vent/drain	1970
VNT-D0714	VNT-D0714	D-714 vent/drain	1970
VNT-D0717	Flare-CC	D-717 depropanizer overhead reflux	1997
VNT-D0741	Flare-CC	D-741 ASO/KOH separator	1985
VNT-D0748	Flare-CC	D-748 fuel gas drum	1971
VNT-D5173	VNT-D5173	D-5173 vent/drain	1944
VNT-Load SF LPG	VNT-Load SF	Loading vent line purge to atmosphere	Est. 1930's
VNT-Load SF Toluene	VNT-Load SF Toluene	Toluene unloading vent to atmosphere	Est. 1930's
VNT-Load SP LPG	VNT-Load SP	Loading and vent line purge to atmosphere	1997
VNT-T0256	Flare-CC	Alky flare slop tank vent	1932
VNT-W0193	Flare-CC	W-193 overhead non-condensables	1970
VNT-D0452	VNT-D0452	D-452 vent/drain	1990

EUG VNT-3: Reserved

EUG VNT-4: 40 CFR Part 63 Subpart GGGGG (Site Remediation MACT) Process Vents

EU ID	Point ID	Equipment	Construction/ Modification Date
VNT-SVE	VNT-SVE	Soil Vapor Extraction (SVE) Vent	1998

EUG VNT-5: Insignificant Activity Atmospheric Process Vents

EU ID	Point ID	Equipment	Insignificant Activity Reason
VNT-C0024	VNT-C0024	No. 5 HDT Hydrogen Compressor Distance Piece Vent	App. I: Miscellaneous – < 5 TPY
VNT-C0060	VNT-C0060	No. 7 HDT Compressor Distance Piece Vent	App. I: Miscellaneous – < 5 TPY
VNT-C0061	VNT-C0061	No. 7 HDT Compressor Distance Piece Vent	App. I: Miscellaneous – < 5 TPY
VNT-C0125	VNT-C0125	No. 3HDS Compressor Distance Piece Vent	App. I: Miscellaneous – < 5 TPY

EU ID	Point ID	Equipment	Insignificant Activity Reason
VNT-C5037	VNT-C5037	Butamer Hydrogen Compressor Distance Piece Vent	App. I: Miscellaneous – < 5 TPY
VNT-D0809	VNT-D0809	Hydrogen Makeup Vent	App. I: Miscellaneous – < 5 TPY
VNT-D8806	VNT-D8806	No. 1 Hydrogen Plant Deaerator Vent	App. I: Miscellaneous – < 5 TPY

EUG VNT-6: Equipment Subject to the Maintenance Vent Provisions of 40 CFR Part 63 Subpart CC (Refinery MACT I)

EU ID	Point ID	Equipment	Approx. Number of Items	Construction/ Modification Date
Refinery-Wide Maintenance Vents	Refinery-Wide Maintenance Vents	Any process vent used as a result of startup, shutdown, maintenance, or inspection of equipment	500	Various

IX.4 FUGITIVE EMISSION EQUIPMENT

EUG FUG-1: Fugitive Equipment Leaks Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) and/or 40 CFR Part 60 Subpart GGGa

EU ID	Point ID	Equipment [1]	Approx. Number of Items	Construction/ Modification Date
Refinery-Wide Piping Equipment Fugitive Leaks	Refinery-Wide Piping Equipment Fugitive Leaks	Gas Valves	24,727	Various
		LL Valves	28,698	Various
		HL Valves	17,928	Various
		Flanges	241,302	Various
		LL Pump Seals	393	Various
		HL Pump Seals	427	Various
		Gas Compressors	20	Various
		Gas Relief Valves to Atm	14	Various
		Gas Relief Valves to Flare	509	Various
		Sample Stations	606	Various

1. LL = Light Liquid; HL = Heavy Liquid.

EUG FUG-2: Fugitive Oily Water Sewer System Component Leaks Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) and 40 CFR Part 61 Subpart FF (Benzene Waste Operations)

EU ID	Point ID	Equipment [(1)]	Approx. Number of Items	Construction/ Modification Date
FUG-Coker ORU	FUG-CC	Process drains	27	1991
		Junction boxes/sumps/WDB	6	1991
FUG-1HP, 2HP, 2Isom, 8HDT, 9HDT, BFU & FGRU	FUG-CF	Process drains	147	Various
		Junction boxes/sumps/WDB	52	2003
FUG-2CTU, 3CRU, 4FCC & ORU	FUG-EP	Process drains	177	Various
		Junction boxes/sumps/WDB	33	Various
FUG-1SWS	FUG-SP	Process drains	10	Various
		Junction boxes/sumps/WDB	1	Various
FUG-2SWS	FUG-SP	Process drains	11	2005
		Junction boxes/sumps/WDB	0	2005
FUG-WP ORU	FUG-WP	Process drains	19	1991
		Junction boxes/sumps/WDB	8	1991
FUG-OM Tank Farm & WWTS	FUG-OM	Process drains	0	NA
		Junction boxes/sumps/WDB	27	Various
FUG-SP Tank Farm	FUG-SP	Process drains	0	NA
		Junction boxes/sumps/WDB	3	Various
FUG-6HDT	FUG-CC	Process drains	13	1992
		Junction boxes/sumps/WDB	12	1992
FUG-TOP	FUG-WP	Process drains	4	2015
		Junction boxes/sumps/WDB	1	2015
FUG-DEC3	FUG-CC	Process drains	4	2017
		Junction boxes/sumps/WDB	1	2017

WDB = water draw box.

EUG FUG-3: Fugitive Oily Water Sewer System Component Leaks Subject to 40 CFR Part 60 Subpart QQQ

EU ID	Point ID	Equipment [(1)]	Approx. Number of Items	Construction/ Modification Date
FUG-7HDT	FUG-WP	Process drains	29	1989
		Junction boxes/sumps/WDB	13	1989

WDB = water draw box.

EUG FUG-4: Fugitive Oily Water Sewer System Component Leaks Subject to 40 CFR Part 61 Subpart FF (Benzene Waste Operations) Exemption Recordkeeping Requirements

EU ID	Point ID	Equipment	Approx. Number of Items	Construction/ Modification Date
Refinery-Wide Oily Water Sewer Component Fugitive Leaks	Refinery-Wide Oily Water Sewer Component Fugitive Leaks	Process drains (controlled)	78	Various
		Process drains (uncontrolled)	2,118	Various
		Junction boxes/sumps (controlled)	0	Various
		Closed drains	243	Various
		Junction boxes/sumps (uncontrolled)	303	Various

EUG FUG-5: Reserved

EUG FUG-6: Cooling Tower Fugitive Sources Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I)

EU ID	Point ID	Equipment	Construction/ Modification Date
Y-0002	Y-0002	West Plant Marley EPHCC01 Cooling Tower	1953
Y-0002A	Y-0002A	West Plant Marley 6615302 Cooling Tower	1973
Y-0003	Y-0003	Coker Cooling Tower	1946
Y-0005	Y-0005	South Plant North & South Loop Cooling Tower	1943
Y-0006	Y-0006	Combo Cooling Tower	1956
Y-0007	Y-0007	Main Power Plant Cooling Tower	2010
Y-0010	Y-0010	Alky Cooling Tower	1971
Y-6026	Y-6026	East Plant Marley Cooling Tower	1953
Y-6027	Y-6027	East Plant Pritchard Cooling Tower	1956
Y-8000	Y-8000	Clean Gasoline Unit Cooling Tower	2003

1. Estimated project timing.

EUG FUG-6.1: Insignificant Cooling Tower Fugitive Sources

The following cooling towers are not subject to any federal or state air quality regulations and are insignificant due to emissions being less than 5 TPY (actual) and therefore, require recordkeeping to verify its insignificance.

EU ID	Point ID	Equipment	Construction/ Modification Date
Y-0009	Y-0009	ASU Cooling Tower	1992

EUG FUG-7: Materials Handling Fugitive Sources Subject to Oklahoma Rules or Permit Requirements

EU ID	Point ID	Equipment	Construction/ Modification Date
Coke Handling Facility	Coke Handling Facility	Railcar Unloading, Truck Loading, Coke Crushing, Drop Points, Wind Erosion, & Coke Truck Traffic	1998

EUG FUG-8: Insignificant Activity Fugitive Sources

EU ID	Point ID	Equipment	Insignificant Activity Reason
Landfarm	Landfarm	Application of ASU Biosludge to Landfarm	App. I: Fugitives – Land farms

EUG COK-1: Delayed Cokers Subject to 40 CFR Part 60 Subpart Ja and 40 CFR Part 63 Subpart CC

EU ID	Point ID	Equipment	Construction/ Modification Date
No. 7 Coker Unit	Coke Drum Operations	Coke Drum Venting, Coke Cutting and Water Handling	1998/2013

IX.5 FACILITY-WIDE

EUG FW: Facility-Wide Applicable Requirements

Source-specific equipment information is not necessary for this EUG.

SECTION X. EMISSIONS

X.1 Criteria Pollutants

Emissions estimates are based on the Ponca City Refinery operating 24 hours per day, every day of the year. Emission estimates are the PTE and were either calculated using the maximum inherent refinery process unit throughputs or permit-limited process unit/individual source throughputs.

For heaters and boilers, the firing rates shown are based on the higher heating value (HHV) of the fuel combusted. Emission estimates are based on emission factors (converted to lb/MMBtu) from either AP-42 Section 1.4 (7/98), vendor data, stack test data, or permitted limits. SO_2 emissions

from heaters and boilers fired with refinery fuel gas (RFG) are based on a hydrogen sulfide content of 0.10 gr/dscf (160 ppmvd @ 60˚F) and a higher heating value of 867 Btu/scf. SO_2 emissions from heaters and boilers fired with RFG that are subject to NSPS Subpart Ja are based on a hydrogen sulfide content of 60 ppmv. SO_2 emissions from heaters and boilers fired with commercial grade natural gas (<0.25 gr H_2S/100 scf, or < 4 ppmv H_2S) are based on a mass balance calculation. Footnotes in the emissions tables for the heaters and boilers have been standardized so that the footnotes are consistent for each table.

Emission estimates for gasoline, diesel, and natural gas-fired engines are based on AP-42 Section 3.3 (10/96) or manufacturer's data where available. Footnotes in the emissions tables for the engines have been standardized so that the footnotes are consistent for each table.

Emission estimates for the fluid catalytic cracking units were taken from current permit limits or based on stack test data.

Catalytic reforming unit catalyst depressuring and purging operation emissions are vented to flare and captured by flare gas recovery.

VOC emissions from storage tanks were calculated using AP-42 (11/06), Section 7.1 and are based on either permitted emission limits, permitted throughput limits, or past actual emission values multiplied by the ratio of current yearly average refinery target crude rate of 184,000 barrels over the actual feed rates during the previous year crude rates for tanks with no emission or throughput limits. For on-site tanks that are out-of-service where historic data was unavailable, throughputs were estimated based on 12 turnovers per year. Although these tanks are currently out-of-service, they have a potential to be used in the future. Therefore, these out-of-service tanks will remain in the permit.

VOC emissions from fugitive components (valves, flanges, pump seals, etc.) were estimated using emission factors that were developed specifically for the Ponca City Refinery. The factors are given in Table 2-1 in a March 1, 1991, letter from Conoco to DEQ titled "Refinery Specific Fugitive Emission Factors – Ponca City Refinery."

VOC emissions from sewer and API separator fugitive sources were estimated using factors from AP-42 (4/15), Section 5.1 and "VOC Emissions from Petroleum Refinery Wastewater Systems - Background Information for Proposed Standards", EPA-450/3-85-001a, Feb. 1985, which is the Background Information Document (BID) for NSPS Subpart QQQ.

VOC emissions from flares were based on a factor from AP-42 (1/95) Table 13.5-1 and the past annual average gas flared, and are represented at the respective flare. NO_X and CO emissions from flares were based on published Texas Commission on Environmental Quality (TCEQ) publication RG-360/14 (Revised 5/2015) factors. SO_2 emissions from flares were calculated based on a stoichiometric conversion of all H_2S to SO_2. There are no published emission factors for PM emissions from flares. The flares are steam assisted and steam is continually injected to improve air and gas mixing which eliminates the formation of particulates during normal operations.

VOC emissions from non-gasoline loading were estimated using the techniques of "Gasoline Distribution Industry (Stage I) – Background Information for Promulgated Standards" (EPA-453/R-94-002b). LPG loading hose purging emissions was estimated using process knowledge.

VOC emissions from Miscellaneous Process Vents were estimated based on process knowledge or test data.

Fugitive VOC emissions from cooling towers were measured using the El Paso Method. Fugitive PM_{10} emissions were based on the methodology described in "Calculating PM_{10} Emissions from Cooling Towers" by Joel Reisman and Gordon Frisbie, Environmental Progress, July 2002, Volume 21, Number 2, Pages 127-130.

Coke Handling Facility emission points include those from coke handling, coke processing, wind erosion, and truck traffic. Various sections of AP-42 were used to estimate PM emissions: 13.2.2 Unpaved Roads (11/06), 13.2.4 Aggregate Handling and Storage Piles (11/06), 13.2.5 Industrial Wind Erosion (11/06), and 11.19.2 Crushed Stone Processing and Pulverized Mineral Processing (8/04).

Emissions are shown to a precision of 0.1 lb/hr and 0.1 TPY. Emissions from a source that are less than 0.05 lb/hr or less than 0.05 TPY are shown as zero but are included in the total emissions for that particular EUG.

EUG TNK-1: Storage Vessels Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) and 40 CFR Part 63 Subpart WW

EU ID	Point ID	Normal Contents	Throughput (gal/yr)	VOC Emissions	
				lb/hr	TPY
T-0021E	T-0021E	Naphtha	8,326,551	0.5	2.3
T-0101	T-0101	Permanently removed from service and replaced by tank T-0102 in 2017.			
T-0114	T-0114	Gasoline	3,650,000	1.9	8.4
T-0148	T-0148	Gasoline	77,186,187	2.1	9.1
T-0149	T-0149	Gasoline	80,559,454	1.2	5.4
T-0150	T-0150	Gasoline	217,296,246	1.3	5.5
T-0151	T-0151	Gasoline	286,395,515	1.3	5.7
T-0154	T-0154	Reformate	341,066,578	3.8	16.7
T-0155	T-0155	Gasoline	274,511,807	2.0	8.6
T-0158	T-0158	Gasoline	221,086,345	1.0	4.4
T-0159	T-0159	Gasoline	96,937,991	1.1	4.8
T-0160	T-0160	Gasoline	159,612,600	1.4	6.1
T-0163	T-0163	LSR Gasoline	343,980,00	1.8	7.8
T-0164	T-0164	LSR Gasoline	27,886,000	4.8	21.2
T-0167	T-0167	Gasoline	4,251,920	0.0	0.1
T-0170	T-0170	Gasoline	96,690,329	0.7	3.2
T-0901	T-0901	Gasoline	252,000,000	4.7	20.5
T-0902	T-0902	Naphtha	252,000,000	4.7	20.5
T-0953	T-0953	Gasoline	252,000,000	3.5	15.3
SUBTOTALS				**37.8**	**165.6**

EUG TNK-2: Storage Vessels Subject to 40 CFR Part 60 Subpart Kb and 40 CFR Part 63 Subpart CC (Refinery MACT I)

EU ID	Point ID	Normal Contents	Throughput (gal/yr)	VOC	
				lb/hr	TPY
T-0014E	T-0014E	Naphtha	2,001,300	0.7	3.3
T-0015	T-0015	Naphtha	2,001,300	0.8	3.3
T-0017E	T-0017E	Crude Oil	40,214,016	0.8	3.6
T-0117	T-0117	Naphtha	636,384,000	3.6	15.8
T-0119	T-0119	Naphtha	630,000,000	7.6	33.5
T-0121	T-0121	Diesel	168,000,000	2.6	11.5
T-0141	T-0141	Slop Oil	1,500,000	5.1	22.3
T-0147	T-0147	Naphtha	252,000,000	2.3	10.1
T-0153	T-0153	Reformate	33,256,716	0.4	1.9
T-0156	T-0156	Gasoline	504,000,000	4.0	17.5
T-0162	T-0162	Gasoline	743,505,000	1.0	4.3
T-0165	T-0165	Alkylate	229,950,000	8.0	35.2
T-0166	T-0166	Gasoline	630,000,000	6.4	27.8
T-0176	T-0176	Toluene	191,625,000	1.3	5.6
T-0177	T-0177	Toluene	2,636,812	0.8	3.7
T-0178	T-0178	Aviation Gasoline	191,625,000	1.1	4.8
T-0357	T-0357	Slop Oil	436,800	0.7	3.1
T-0402	T-0402	Slop Oil	218,400	0.7	3.1
T-0540	T-0540	Methanol	132,842	0.0	0.2
T-0690	T-0690	Slop Oil	840,000	0.7	3.1
T-0944	T-0944	Sour Water	18,593,161	0.3	1.4
SUBTOTALS				**48.9**	**215.1**

EUG TNK-3 Storage Vessels Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) Recordkeeping

EU ID	Point ID	Normal Contents	Throughput (gal/yr)	VOC Emissions	
				lb/hr	TPY
D-0924	D-0924	MDEA	334,800	0.6	2.7
T-0003	T-0003	Dye	117,600	0.0	0.0
T-0038	T-0038	Crude Oil	1,115,589,966	2.9	12.8
T-0064	T-0064	Diesel	1,644,895	0.0	0.0
T-0070	T-0070	Spent Caustic	1,839,179	0.0	0.1
T-0077	T-0077	Spent Caustic	646,680	0.0	0.0
T-0102	T-0102	Diesel	1,050,000	0.1	0.5
T-0106E	T-0106E	Gas Oil	16,992,842	8.9	39.2
T-0107E	T-0107E	Gas Oil	291,270,000	4.7	20.6
T-0120	T-0120	Gas Oil	919,800,000	5.4	23.7
T-0123	T-0123	Diesel	588,000,000	3.2	14.0
T-0124	T-0124	Diesel	588,000,000	3.2	14.0
T-0125	T-0125	Diesel	588,000,000	3.2	14.0
T-0126	T-0126	Diesel	588,000,000	3.2	14.0

EU ID	Point ID	Normal Contents	Throughput (gal/yr)	VOC Emissions	
				lb/hr	TPY
T-0128	T-0128	Jet Fuel	420,000,000	2.8	12.2
T-0129	T-0129	Diesel	420,000,000	2.8	12.2
T-0130	T-0130	Diesel	630,000,000	4.9	21.4
T-0131	T-0131	Diesel	630,000,000	4.9	21.4
T-0135	T-0135	Diesel	588,000,000	3.7	16.0
T-0136	T-0136	Diesel	588,000,000	3.6	16.0
T-0142	T-0142	Residuum	7,702,851	0.0	0.2
T-0143	T-0143	Residuum	306,600,000	3.0	13.1
T-0144	T-0144	Residuum	12,906,295	8.5	37.1
T-0152	T-0152	Gas Oil	33,776,400	0.0	0.0
T-0161	T-0161	Gas Oil	1,881,944	0.1	0.3
T-0168	T-0168	Jet Fuel	7,259,810	0.0	0.2
T-0169	T-0169	Jet Fuel	7,899,245	0.1	0.2
T-0171	T-0171	Vendor Chemical	2,478,372	0.0	0.0
T-0179	T-0179	Jet Fuel	40,000,000	1.1	5.0
T-0253	T-0253	Spent Caustic/HC	26,280,000	2.2	9.6
T-0254[(1)]	T-0254	Spent Caustic/HC	26,280,000 [combined for these 2 tanks]	2.0	8.6
T-0509[(1)]	T-0509	Spent Caustic/HC			
T-0260	T-0260	Caustic/HC	317,244	0.0	0.0
T-0500	T-0500	Gas Oil	31,399,064	0.5	2.4
T-0501	T-0501	Coker Fines Water/HC	77,873,250	0.1	0.6
T-0536	T-0536	Seal Oil	5,518,240	0.0	0.1
T-0561	T-0561	Hydrocarbon	24,418	0.0	0.0
T-0633	T-0633	Jet Fuel	48,037,352	0.2	1.0
T-0636	T-0636	Jet Fuel	53,830,803	0.5	2.1
T-0639	T-0639	Jet Fuel	84,000,000	0.3	1.4
T-0904	T-0904	Gas Oil	26,731,512	0.1	0.6
T-0905	T-0905	Gas Oil	140,794,902	12.7	55.6
T-0906	T-0906	Gas Oil	9,286,419	0.0	0.2
T-0913	T-0913	Gas Oil	5,345,380	0.0	0.1
T-0914	T-0914	Gas Oil	12,262,607	0.0	0.2
T-0916	T-0916	Gas Oil	297,717,911	1.1	4.6
T-0970	T-0970	Residuum	12,643,582	0.1	0.5
T-0971	T-0971	Residuum	13,565,104	0.2	0.7
T-0972	T-0972	Residuum	14,047,738	0.2	0.8
SUBTOTALS				**90.5**	**400.0**

1. These two tanks are operated in parallel, essentially as a single storage vessel.

EUG TNK-4: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 1 Wastewater Streams Handled by Either Tanks or Storage Vessels

EU ID	Point ID	Normal Contents	Throughput (gal/yr)	VOC Emissions	
				lb/hr	TPY
D-0777	D-0777	Wastewater	6,768	0.0	0.0
D-0779	D-0779	Wastewater	124,836	0.0	0.0
D-5292	D-5292	Spent Caustic/HC	22,800	0.0	0.0

EU ID	Point ID	Normal Contents	Throughput (gal/yr)	VOC Emissions	
				lb/hr	TPY
T-0037	T-0037	Slop Oil	1,522,500,000	4.1	17.8
T-0201	T-0201	Slop Oil	7,364,056,518	4.9	21.6
T-0202	T-0202	Slop Oil	7,591,350,396	5.1	22.2
T-0203	T-0203	Slop Oil	165,868,584	0.5	2.0
T-0204	T-0204	Wastewater	7,359,192,246	4.9	21.5
T-0205	T-0205	Wastewater	7,342,830,600	4.9	21.5
T-0551	T-0551	Wastewater	4,733,568	4.9	21.5
T-0552	T-0552	Wastewater	4,985,946	4.9	21.5
T-0553[(1)]	T-0553	Slop Oil	2,542,000 [combined for these 2 tanks]	9.7	42.5
T-0554[(1)]	T-0554	Slop Oil			
T-0555	T-0555	Slop Oil	691,152	0.5	2.0
T-0651	T-0651	Wastewater	6,458,543	0.1	0.3
T-0652	T-0652	Wastewater	5,705,544	0.1	0.5
T-0654	T-0654	Wastewater	20,103,196,764	6.2	27.4
T-0665	T-0665	Wastewater	19,009,124,946	6.1	26.6
T-0667	T-0667	Slop Oil	3,599,963	0.5	2.0
T-0669	T-0669	Spent Caustic/HC	2,128,714	4.8	21.0
T-0701	T-0701	Slop Oil	5,212,589,634	0.5	2.1
T-0702	T-0702	Slop Oil	5,212,589,634	4.7	20.8
T-0703	T-0703	Slop Oil	335,882,820	4.7	20.8
T-0704	T-0704	Wastewater	5,208,070,098	0.9	3.8
T-0705	T-0705	Wastewater	5,208,070,098	4.8	20.8
T-0706	T-0706	Wastewater	26,279,266	4.8	20.8
T-907	T-907	Sour Water	3,037,330	0.2	1.0
T-908	T-908	Sour Water	12,600,000	0.7	3.2
T-0910	T-0910	Slop Oil	6,300,000	0.9	4.0
SUBTOTALS				**84.5**	**369.2**

1. These two tanks are operated in parallel, essentially as a single storage vessel.

EUG TNK-5: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 2 Wastewater Streams Handled by Storage Tanks

EU ID	Point ID	Normal Contents	Throughput (gal/yr)	VOC Emissions	
				lb/hr	TPY
D-0232	D-0232	Wastewater	11,088	0.0	0.0
D-0775	D-0775	Wastewater	29,498,062	0.3	1.3
D-0776	D-0776	Wastewater	29,498,062	0.3	1.3
D-0780	D-0780	Wastewater	124,836	0.1	0.4
D-0783	D-0783	Wastewater	74,710,999	0.7	3.1
D-0786-1	D-0786-1	Wastewater	6,768	0.0	0.0
D-6801	D-6801	Wastewater	121,727,109	1.5	6.5
D-6812	D-6812	Wastewater	121,727,109	1.2	5.2
T-0080	T-0080	Slop Oil	124,592	0.1	0.5
T-0140	T-0140	Wastewater	46,356	0.0	0.1
T-0173	T-0173	Brine Water/HC	2,573,760	0.0	0.0
T-0648	T-0648	Wastewater	54,912	0.0	0.1

EU ID	Point ID	Normal Contents	Throughput (gal/yr)	VOC Emissions	
				lb/hr	TPY
T-0680	T-0680	ASU Lift Station Overflow	95,045,625	1.0	4.2
T-0966	T-0966	Slop Oil	64,603	0.0	0.1
T-0973	T-0973	Spent Caustic/HC	2,729,033	2.7	12.0
SUBTOTALS				**8.7**	**38.2**

EUG TNK-6: 40 CFR Part 63 Subpart EEEE (OLD MACT) Fixed Roof Storage Tanks

EU ID	Point ID	Normal Contents	Throughput (gal/yr)	VOC Emissions	
				lb/hr	TPY
T-0017	T-0017	Perchloroethylene	4,200	0.0	0.0
T-0018	T-0018	Perchloroethylene	4,200	0.0	0.0
T-0027	T-0027	Methanol	6,600	0.0	0.0
T-0057	T-0057	Methanol	6,600	0.0	0.0
T-0058	T-0058	Methanol	6,600	0.0	0.0
T-0104	T-0104	Methanol	20,160	0.0	0.0
T-0212 E	T-0212 E	Vendor Chemical	6,552	0.0	0.1
T-0230	T-0230	Glycol Water	120,000	0.0	0.0
T-0527	T-0527	Methanol	6,600	0.0	0.0
T-0528	T-0528	Methanol	6,600	0.0	0.0
T-0529	T-0529	Methanol	6,600	0.0	0.0
T-0542	T-0542	Methanol	6,600	0.0	0.0
T-0111	T-0111	Methanol	6,600	0.0	0.0
T-0511	T-0511	Methanol	6,600	0.0	0.0
T-0538	T-0538	Methanol	6,600	0.0	0.0
T-0540 TOTE	T-0540 TOTE	Methanol	6,600	0.0	0.0
T-0543	T-0543	Methanol	6,600	0.0	0.0
T-2254	T-2254	Methanol	6,600	0.0	0.0
T-5005	T-5005	Methanol	6,600	0.0	0.0
T-9403	T-9403	Methanol	6,600	0.0	0.0
NP Methanol Tote	NP Methanol Tote	Methanol	6,600	0.0	0.0
TNK-Misc. Vendor Totes/Tanks(1)	TNK-Misc. Vendor Totes/Tanks(1)	Vendor Chemical	1,200,000	0.0	0.0
SUBTOTALS				**0.0**	**0.1**

1. Emissions based on 50 vendor tanks combined.

EUG TNK-7: Storage Tanks Subject to Oklahoma Rules or Permit Requirements

EU ID	Point ID	Normal Contents	Throughput (gal/yr)	VOC Emissions	
				lb/hr	TPY
T-0024	T-0024	Gasoline	113,509	0.1	0.6
TNK-MP Gasoline	TNK-MP Gasoline	Gasoline	22,234	0.0	0.1
TNK-GFMHL #1	TNK-GFMHL #1	Gasoline	6,000	0.0	0.1
TNK-GFMRW #1	TNK-GFMRW #1	Gasoline	6,000	0.0	0.1
TNK-GFMNT1	TNK-GFMNT1	Gasoline	6,000	0.1	0.4

EU ID	Point ID	Normal Contents	Throughput (gal/yr)	VOC Emissions	
				lb/hr	TPY
SUBTOTALS				**0.2**	**1.3**

EUG TNK-8: Insignificant Activity Storage Tanks

Emissions estimates for individual insignificant activities are not necessary since the facility is already a Part 70 major source.

EUG HTR-1: 40 CFR Part 60 Subparts J, Db, & Dc and 40 CFR Part 63 Subpart DDDDD Boilers

EU ID	Point ID	Fired Duty (MMBtu/hr)	Pollutant	EF (lb/MMBtu)	Emissions	
					lb/hr	TPY
B-0008	B-0008	483	NO_X	0.035(2)	16.9	74.0
			CO	0.0824(3)	39.8	174.0
			SO_2	0.031(4)	15.0	65.6
			VOC	0.0054(3)	2.6	11.4
			PM_{10}	0.0075(3)	3.6	15.9
B-0009/0010	B-0009/0010	734 (1)	NO_X	0.0500(2)	36.6	161.0
			CO	0.0400(2)	29.4	129.0
			SO_2	0.031(3)	22.8	99.7
			VOC	0.0054(3)	3.96	17.4
			PM_{10}	0.0075(3)	5.52	24.2
B-0021	Permanently removed from service by June 2012 and shall not be returned to service.					
B-0022	B-0022 (SC 33)	95	NO_X	0.036(2)	3.42	15.0
			CO	0.04(2)	3.80	16.6
			SO_2	0.0006(4)	0.05	0.2
			VOC	0.0054(3)	0.51	2.2
			PM_{10}	0.0075(3)	0.71	3.1
SUBTOTALS			**NO_X**	-	**56.9**	**250.0**
			CO	-	**73.0**	**319.6**
			SO_2	-	**37.9**	**165.5**
			VOC	-	**7.1**	**31.0**
			PM_{10}	-	**9.8**	**43.2**

1. The boilers share a common stack. The fired duty shown is a total for both boilers.
2. Based on permit limit.
3. Based on AP-42 Section 1.4 (7/98).
4. Based on mass balance assuming NSPS Subpart J or Subpart Ja H_2S limit, or commercial grade natural gas specifications.

EUG HTR-2: 40 CFR Part 60 Subpart J Heaters & Boilers

EU ID	Point ID	Fired Duty (MMBtu/hr)	Pollutant	EF (lb/MMBtu)	Emissions	
					lb/hr	TPY
B-0006	Permanently removed from service by July 31, 2009 and shall not be returned to service.					
B-0007						
B-5004	Permanently removed from service by December 31, 2022 and shall not be returned to service.					
H-0001	Permanently removed from service by September 24, 2017 and shall not be returned to service					
H-0003	H-0003	32	NO_X	0.098(3)	3.2	13.8
			CO	0.039(2)	1.3	5.5
			SO_2	0.011(4)	0.3	1.4
			VOC	0.0054(3)	0.2	0.8
			PM_{10}	0.0075(3)	0.2	1.0
H-0004	H-0004	118	NO_X	0.127(5)	15.0	65.6
			CO	0.039(2)	4.6	20.1
			SO_2	0.011(4)	1.2	5.1
			VOC	0.0054(3)	0.6	2.8
			PM_{10}	0.0075(3)	0.9	3.9
H-0005	Permanently removed from service by September 24, 2017 and shall not be returned to service					
H-0010	H-0010	55	NO_X	0.098(2)	5.4	23.6
			CO	0.0824(3)	4.5	19.9
			SO_2	0.031(4)	1.7	7.5
			VOC	0.0054(3)	0.3	1.3
			PM_{10}	0.0075(3)	0.4	1.8
H-0011	H-0011	18	NO_X	0.118(2)	12.2	9.5
			CO	0.0824(3)	1.5	6.5
			SO_2	0.011(4)	0.2	0.8
			VOC	0.0054(3)	0.1	0.4
			PM_{10}	0.0075(3)	0.1	0.6
H-0016	H-0016	107	NO_X	0.035(2)	3.7	16.4
			CO	0.04(2)	4.3	18.7
			SO_2	0.031(4)	3.3	14.5
			VOC	0.0054(3)	0.6	2.5
			PM_{10}	0.0075(3)	0.8	3.5
H-0023	H-0023	52.4	NO_X	0.137(3)	7.2	31.4
			CO	0.0824(3)	4.3	18.9
			SO_2	0.031(4)	1.6	7.1
			VOC	0.0054(3)	0.3	1.2
			PM_{10}	0.0075(3)	0.4	1.7
H-0028	H-0028/0029	129	NO_X	0.137(3)	14.1	62.0
			CO	0.0824(3)	10.6	47.0
			SO_2	0.031(4)	4.0	17.5
			VOC	0.0054(3)	0.7	3.0
			PM_{10}	0.0075(3)	1.0	5.0

EU ID	Point ID	Fired Duty (MMBtu/hr)	Pollutant	EF (lb/MMBtu)	Emissions	
					lb/hr	TPY
H-0029	H-0028/0029	75	NO_X	0.098(3)	7.4	32.2
			CO	0.0824(3)	6.2	27.1
			SO_2	0.031(4)	2.3	10.2
			VOC	0.0054(3)	0.4	1.8
			PM_{10}	0.0075(3)	0.6	2.4
H-0046	H-0046	48.0	NO_X	0.098(3)	4.7	21.0
			CO	0.0824(3)	4.0	18.0
			SO_2	0.031(4)	1.5	6.5
			VOC	0.0054(3)	0.3	1.1
			PM_{10}	0.0075(3)	0.4	2.0
H-0048	H-0048	241.4	NO_X	0.07(2)	16.9	74.0
			CO	0.04(2)	9.7	42.3
			SO_2	0.031(4)	7.5	32.7
			VOC	0.0054(3)	1.3	5.7
			PM_{10}	0.0075(3)	1.8	7.9
H-0057	Permanently removed from service by February 28, 2009 and shall not be returned to service.					
H-0058						
H-0059						
H-1001	H-1001	30	NO_X	0.05(2)	1.5	6.6
			CO	0.04(2)	1.2	5.3
			SO_2	0.031(4)	0.9	4.1
			VOC	0.0054(3)	0.2	0.7
			PM_{10}	0.0075(3)	0.2	1.0
H-5001	Permanently removed from service by December 18, 2008 and shall not be returned to service.					
H-6005	H-6005	170	NO_X	0.075(2)	11.8	51.6
			CO	0.082(3)	12.9	56.4
			SO_2	0.031(4)	4.9	21.3
			VOC	0.005(3)	0.9	3.8
			PM_{10}	0.007(3)	1.2	5.2
H-6007	H-6007	150	NO_X	0.065(2)	9.7	42.7
			CO	0.04(2)	6.0	26.3
			SO_2	0.031(4)	4.7	20.4
			VOC	0.0054(3)	0.8	3.5
			PM_{10}	0.0075(3)	1.1	4.9
H-6008	H-6008	2	NO_X	0.098(3)	0.2	1.0
			CO	0.0824(3)	0.2	1.0
			SO_2	0.031(4)	0.1	0.3
			VOC	0.0054(3)	0.0	0.1
			PM_{10}	0.0075(3)	0.0	1.0
H-6012	H-6012	25	NO_X	0.098(3)	2.5	11.0
			CO	0.0824(3)	2.1	9.0
			SO_2	0.031(4)	0.8	3.4
			VOC	0.0054(3)	0.1	0.6
			PM_{10}	0.0075(3)	0.2	1.0

EU ID	Point ID	Fired Duty (MMBtu/hr)	Pollutant	EF (lb/MMBtu)	Emissions	
					lb/hr	TPY
H-6013	H-6013	75.8	NO_X	0.06[2]	4.6	19.9
			CO	0.04[2]	3.0	13.3
			SO_2	0.031[4]	2.3	10.3
			VOC	0.0054[3]	0.4	1.8
			PM_{10}	0.0075[3]	0.6	2.5
H-6014	H-6014	72	NO_X	0.05[2]	3.6	15.8
			CO	0.04[2]	2.9	12.6
			SO_2	0.031[4]	2.2	9.8
			VOC	0.0054[3]	0.4	1.7
			PM_{10}	0.0075[3]	0.5	2.3
H-6015	H-6015	79	NO_X	0.06[2]	4.8	20.8
			CO	0.04[2]	3.2	13.8
			SO_2	0.031[4]	2.4	10.7
			VOC	0.0054[3]	0.4	1.8
			PM_{10}	0.0075[3]	0.6	2.6
H-6151	H-6151	80	NO_X	0.098[3]	7.8	34.3
			CO	0.0824[3]	6.6	28.9
			SO_2	0.031[4]	2.5	10.9
			VOC	0.0054[3]	0.4	1.9
			PM_{10}	0.0075[3]	0.6	2.6
H-7501	H-7501	36.6	NO_X	0.11[2]	4.1	18.0
			CO	0.0824[3]	1.2	5.4
			SO_2	0.031[4]	1.1	5.0
			VOC	0.0054[3]	0.2	1.0
			PM_{10}	0.0075[3]	0.3	1.3
H-8601	H-8601	120	NO_X	0.035[3]	4.2	18.4
			CO	0.0824[2]	9.9	43.3
			SO_2	0.031[4]	3.7	16.3
			VOC	0.0054[3]	0.7	2.9
			PM_{10}	0.0075[3]	0.9	3.9
H-8602	H-8602	36	NO_X	0.035[2]	1.3	5.5
			CO	0.0824[3]	3.0	13.0
			SO_2	0.031[4]	1.1	4.9
			VOC	0.0054[3]	0.2	0.8
			PM_{10}	0.0075[3]	0.3	1.2
H-8801/8802	H-8801/8802	123	NO_X	0.035[2]	4.3	18.9
			CO	0.0824[3]	10.1	44.2
			SO_2	0.0006[4]	0.1	0.3
			VOC	0.0054[3]	0.7	2.9
			PM_{10}	0.0075[3]	0.9	4.0
H-9851	H-9851	282	NO_X	0.075[2]	21.2	92.8
			CO	0.04[2]	11.3	49.5
			SO_2	0.031[4]	8.7	38.3
			VOC	0.0054[3]	1.5	6.7
			PM_{10}	0.0075[3]	2.1	9.3

EU ID	Point ID	Fired Duty (MMBtu/hr)	Pollutant	EF (lb/MMBtu)	Emissions	
					lb/hr	TPY
H-9901	H-9901	40	NO_X	0.05[2]	2.0	8.8
			CO	0.04[2]	1.6	7.0
			SO_2	0.031[4]	1.2	5.4
			VOC	0.0054[3]	0.2	1.0
			PM_{10}	0.0075[3]	0.3	1.3
H-9902	H-9902	50	NO_X	0.05[2]	2.5	11.0
			CO	0.04[2]	2.0	8.8
			SO_2	0.031[4]	1.6	6.8
			VOC	0.0054[3]	0.3	1.2
			PM_{10}	0.0075[3]	0.4	1.6
SUBTOTALS			**NO_X**	-	**178.6**	**738.5**
			CO	-	**128.2**	**561.8**
			SO_2	-	**61.9**	**271.5**
			VOC	-	**12.2**	**53.0**
			PM_{10}	-	**16.8**	**75.5**

1. Reserved.
2. Based on permit limit.
3. Based on AP-42 Section 1.4 (7/98).
4. Based on mass balance assuming NSPS Subpart J or Subpart Ja H_2S limit, or commercial grade natural gas specifications.
5. Based on stack testing plus a safety factor of 1.15.

EUG HTR-2.1: 40 CFR Part 60 Subpart Ja and 40 CFR Part 63 Subpart DDDDD Heaters & Boilers

EU ID	Point ID	Fired Duty (MMBtu/hr)	Pollutant	EF (lb/MMBtu)	Emissions	
					lb/hr	TPY
H-0001	H-0001	275	NO_X	0.05[2]	13.8	60.2
			CO	0.04[2]	11.0	48.2
			SO_2	0.012[4]	3.2	14.1
			VOC	0.0054[3]	1.5	6.5
			PM_{10}	0.0075[3]	2.1	9.0
H-0060	H-0060	147	NO_X	0.05[2]	6.4	28.0
			CO	0.04[2]	5.1	22.4
			SO_2	0.031[4]	4.0	17.4
			VOC	0.0054[3]	0.8	3.4
			PM_{10}	0.0075[3]	1.1	4.8
H-9301	H-9301	131	NO_X	0.03[2]	3.9	17.3
			CO	0.04[2]	5.3	23.0
			SO_2	0.012[4]	1.6	6.9
			VOC	0.0054[3]	0.7	3.1
			PM_{10}	0.0075[3]	1.0	4.3

EU ID	Point ID	Fired Duty (MMBtu/hr)	Pollutant	EF (lb/MMBtu)	Emissions	
					lb/hr	TPY
H-5002	H-5002	120	NO_X	0.040(2)	4.8	21.0
			CO	0.04(2)	4.8	21.0
			SO_2	0.031(4)	3.7	16.3
			VOC	0.0054(3)	0.7	2.9
			PM_{10}	0.0075(3)	0.9	3.9
SUBTOTALS			**NO_X**	-	**28.9**	**126.5**
			CO	-	**26.2**	**144.6**
			SO_2	-	**12.5**	**54.7**
			VOC	-	**3.7**	**15.9**
			PM_{10}	-	**5.1**	**22.0**

1. Reserved.
2. Based on permit limit.
3. Based on AP-42 Section 1.4 (7/98).
4. Based on mass balance assuming NSPS Subpart J or Subpart Ja H_2S limit, or commercial grade natural gas specifications.

EUG HTR-2.2 Boilers Subject to 40 CFR Part 63 Subpart DDDDD

EU ID	Point ID	Fired Duty (MMBtu/hr)	Pollutant	EF (lb/MMBtu)	Emissions	
					lb/hr	TPY
BLR-GFMRW1	BLR-GFMRW1	20.9	NO_X	0.098(3)	2.0	9.0
			CO	0.0824(3)	1.7	7.5
			SO_2	0.0006(4)	0.0	0.1
			VOC	0.0054(3)	0.1	0.5
			PM_{10}	0.0075(3)	0.2	0.7
BLR-GFMRW3	BLR-GFMRW3	20.9	NO_X	0.098(3)	2.0	9.0
			CO	0.0824(3)	1.7	7.5
			SO_2	0.0006(4)	0.0	0.1
			VOC	0.0054(3)	0.1	0.5
			PM_{10}	0.0075(3)	0.2	0.7
BLR-GFMRW4	BLR-GFMRW4	14.6	NO_X	0.098(3)	1.4	6.3
			CO	0.0824(3)	1.2	5.3
			SO_2	0.0006(4)	0.0	0.0
			VOC	0.0054(3)	0.1	0.3
			PM_{10}	0.0075(3)	0.1	0.5
BLR-GFMRW5	BLR-GFMRW5	14.6	NO_X	0.098(3)	1.4	6.3
			CO	0.0824(3)	1.2	5.3
			SO_2	0.0006(4)	0.0	0.0
			VOC	0.0054(3)	0.1	0.3
			PM_{10}	0.0075(3)	0.1	0.5
BLR-GFMRW6	BLR-GFMRW6	14.6	NO_X	0.098(3)	1.4	6.3
			CO	0.0824(3)	1.2	5.3
			SO_2	0.0006(4)	0.0	0.0
			VOC	0.0054(3)	0.1	0.3
			PM_{10}	0.0075(3)	0.1	0.5

EU ID	Point ID	Fired Duty (MMBtu/hr)	Pollutant	EF (lb/MMBtu)	Emissions	
					lb/hr	TPY
SUBTOTALS			**NO_X**	**-**	**8.4**	**36.7**
			CO	**-**	**7.1**	**30.9**
			SO_2	**-**	**0.1**	**0.2**
			VOC	**-**	**0.5**	**2.0**
			PM_{10}	**-**	**0.6**	**2.8**

1. Reserved.
2. Reserved.
3. Based on AP-42 Section 1.4 (7/98).
4. Based on mass balance assuming NSPS Subpart J or Subpart Ja H_2S limit, or commercial grade natural gas specifications.

EUG HTR-3 Heaters & Boilers Subject to Oklahoma Rules or Permit Limits

EU ID	Point ID	Fired Duty (MMBtu/hr)	Pollutant	EF (lb/MMBtu)	Emissions	
					lb/hr	TPY
H-6037A/ 6037B (1)	No. 4 FCCU	23.4	NO_X	-	0.0	0.0
			CO	-	0.0	0.0
			SO_2	-	0.0	0.0
			VOC	-	0.0	0.0
			PM_{10}	-	0.0	0.0
HTR-5FCC Converter Air Preheater (1)	No. 5 FCCU	Est. > 10 but <50	NO_X	-	0.0	0.0
			CO	-	0.0	0.0
			SO_2	-	0.0	0.0
			VOC	-	0.0	0.0
			PM_{10}	-	0.0	0.0
SUBTOTALS			**NO_X**	**-**	**0.0**	**0.0**
			CO	**-**	**0.0**	**0.0**
			SO_2	**-**	**0.0**	**0.0**
			VOC	**-**	**0.0**	**0.0**
			PM_{10}	**-**	**0.0**	**0.0**

1. Emissions from H-6037A/6037B and HTR-5FCC are included in EUG-FCC-1.

EUG HTR-4 Insignificant Activity Heaters & Boilers

Emissions estimates for individual insignificant activities are not necessary since facility is already a Title V major source.

EUG ENG-1a: Existing 2SLB Engines >500-hp "Subject" to 40 CFR Part 63 Subpart ZZZZ (RICE MACT) but With No Emission Limitations or Operating Requirements

Note: Not all engines operate continuously. TPY emissions are based on actual hours of operation. These engines have no emissions limits.

EU ID	Point ID	Horsepower [1]	Pollutant	EF (lb/hp-hr)	Emissions	
					lb/hr	TPY
E-0068	E-0068	550	NO_X	0.0222[3]	12.2	53.5
			CO	0.0027[3]	1.5	6.5
			SO_2	4.12E-06[3]	0.0	0.0
			VOC	0.00084[3]	0.5	2.0
			PM_{10}	0.00027[3]	0.2	0.7
E-0072	E-0072	600	NO_X	0.0222[3]	13.3	58.3
			CO	0.0027[3]	1.62	7.1
			SO_2	4.12E-06[3]	0.0	0.0
			VOC	0.00084[3]	0.5	2.2
			PM_{10}	0.00027[3]	0.2	0.7
SUBTOTAL			**NO_X**	-	**25.5**	**111.8**
			CO	-	**3.1**	**13.6**
			SO_2	-	**0.0**	**0.0**
			VOC	-	**1.0**	**4.2**
			PM_{10}	-	**0.4**	**1.4**

1. Horsepower is shown for the purposes of regulatory applicability only and is not to be construed as a limit.
2. Reserved.
3. Based on AP-42 Section 3.2 (7/00).

EUG ENG-1b: Existing Emergency Engines >500-hp "Subject" to 40 CFR Part 63 Subpart ZZZZ (RICE MACT) but With No Emission Limitations or Operating Requirements

Note: Not all engines operate continuously. TPY emissions are based on actual hours of operation. These engines have no emissions limits.

EU ID	Point ID	Horsepower [1]	Pollutant	EF (lb/hp-hr)	Emissions	
					lb/hr	TPY
ENG-GFMPB	ENG-GFMPB	732	NO_X	0.024[4]	17.6	4.4
			CO	0.0055[4]	4.0	1.0
			SO_2	0.0021[6]	1.5	0.4
			VOC	0.0007[4]	0.5	0.1
			PM_{10}	0.0007[4]	0.5	0.1

1. Horsepower is shown for the purposes of regulatory applicability only and is not to be construed as a limit.
2. Reserved.
3. Reserved.
4. Based on AP-42 Section 3.4 (10/96).
5. Reserved.
6. Based on mass balance with sulfur content in fuel.

EUG ENG-2: CI Emergency Engines 500-hp or Less Subject to 40 CFR Part 63 Subpart ZZZZ (RICE MACT) Table 2c Requirements

Note: Not all engines operate continuously. TPY emissions are based on actual hours of operation. These engines have no emissions limits.

EU ID	Point ID	Horsepower [1]	Pollutant	EF (lb/hp-hr)	Emissions	
					lb/hr	TPY
E-0003[2]	E-0003	482	NO_X	0.0310[4]	14.9	3.7
			CO	0.0067[4]	3.2	0.8
			SO_2	0.0021[4]	1.0	0.2
			VOC	0.0025[4]	1.2	0.3
			PM_{10}	0.0022[4]	1.1	0.3
E-0004	E-0004	482	NO_X	0.0310[4]	14.9	3.7
			CO	0.0067[4]	3.2	0.8
			SO_2	0.0021[4]	1.0	0.2
			VOC	0.0025[4]	1.2	0.3
			PM_{10}	0.0022[4]	1.1	0.3
E-0061	E-0061	375	NO_X	0.0310[4]	11.6	2.9
			CO	0.0067[4]	2.5	0.6
			SO_2	0.0021[4]	0.8	0.2
			VOC	0.0025[4]	0.9	0.2
			PM_{10}	0.0022[4]	0.8	0.2
E-0062	E-0062	375	NO_X	0.0310[4]	11.6	2.9
			CO	0.0067[4]	2.5	0.6
			SO_2	0.0021[4]	0.8	0.2
			VOC	0.0025[4]	0.9	0.2
			PM_{10}	0.0022[4]	0.8	0.2
E-0158	Permanently removed from service by August 31, 2018 and shall not be returned to service.					
E-ALKY	E-ALKY	58	NO_X	0.0125[5]	0.7	0.2
			CO	0.0012[5]	0.1	0.0
			SO_2	0.00001[6]	0.0	0.0
			VOC	0.0012[5]	0.1	0.0
			PM_{10}	0.0003[5]	0.0	0.0
E-GFMCB	E-GFMCB	207	NO_X	0.0144[5]	3.0	0.7
			CO	0.0019[5]	0.4	0.1
			SO_2	0.0013[5]	0.3	0.1
			VOC	0.0003[5]	0.1	0.0
			PM_{10}	0.0006[5]	0.1	0.0
E-GFMSB	E-GFMSB	207	NO_X	0.0150[5]	3.1	0.8
			CO	0.0050[5]	1.0	0.3
			SO_2	0.0021[4]	0.4	0.1
			VOC	0.0004[5]	0.1	0.0
			PM_{10}	0.0011[5]	0.2	0.1
E-GFMST	E-GFMST	165	NO_X	0.0310[4]	5.1	1.3
			CO	0.0067[4]	1.1	0.3
			SO_2	0.0021[4]	0.3	0.1
			VOC	0.0025[4]	0.4	0.1
			PM_{10}	0.0022[4]	0.4	0.1

EU ID	Point ID	Horsepower (1)	Pollutant	EF (lb/hp-hr)	Emissions	
					lb/hr	TPY
SUBTOTALS			**NO_X**	**-**	**65.0**	**16.2**
			CO	**-**	**14.0**	**3.5**
			SO_2	**-**	**4.7**	**1.1**
			VOC	**-**	**4.8**	**1.2**
			PM_{10}	**-**	**4.5**	**1.1**

1. Horsepower is shown for the purposes of regulatory applicability only and is not to be construed as a limit.
2. Emergency generators, fire water pump drivers, and emergency back-up instrument air compressor drivers assumed to operate 500 hrs/yr.
3. Reserved.
4. Based on AP-42 Section 3.3 (10/96).
5. Based on vendor-provided factors.
6. Based on mass balance with sulfur content in fuel.

EUG ENG-3: 4SLB Non-Emergency Engines <100-hp Subject to 40 CFR Part 63 Subpart ZZZZ (RICE MACT) Table 2c Requirements

Note: Not all engines operate continuously. TPY emissions are based on actual hours of operation. These engines have no emissions limits.

EU ID	Point ID	Horsepower (1)	Pollutant	EF (lb/hp-hr)	Emissions	
					lb/hr	TPY
E-0075	E-0075	4	NO_X	0.0310(3)	0.1	0.5
			CO	0.0067(3)	0.0	0.1
			SO_2	0.0021(3)	0.0	0.0
			VOC	0.0025(3)	0.0	0.0
			PM_{10}	0.0022(3)	0.0	0.0
E-0104	E-0104	4	NO_X	0.0310(3)	0.1	0.5
			CO	0.0067(3)	0.0	0.1
			SO_2	0.0021(3)	0.0	0.0
			VOC	0.0025(3)	0.0	0.0
			PM_{10}	0.0022(3)	0.0	0.0
E-0106	E-0106	4	NO_X	0.0310(3)	0.1	0.5
			CO	0.0067(3)	0.0	0.1
			SO_2	0.0021(3)	0.0	0.0
			VOC	0.0025(3)	0.0	0.0
			PM_{10}	0.0022(3)	0.0	0.0
E-LABB	E-LABB	4	NO_X	0.0310(3)	0.1	0.5
			CO	0.0067(3)	0.0	0.1
			SO_2	0.0021(3)	0.0	0.0
			VOC	0.0025(3)	0.0	0.0
			PM_{10}	0.0022(3)	0.0	0.0
SUBTOTALS			**NO_X**	**-**	**0.4**	**2.0**
			CO	**-**	**0.0**	**0.4**
			SO_2	**-**	**0.0**	**0.0**
			VOC	**-**	**0.0**	**0.0**
			PM_{10}	**-**	**0.0**	**0.0**

1. Horsepower is shown for the purposes of regulatory applicability only and is not to be construed as a limit.

2. Emergency generators, fire water pump drivers, and emergency back-up instrument air compressor drivers assumed to operate 500 hrs/yr.
3. Based on AP-42 Section 3.2 (7/00).

EUG ENG-4: Emergency CI Engines Subject to 40 CFR Part 60 Subpart IIII

Note: Not all engines operate continuously. TPY emissions are based on actual hours of operation. These engines have no emissions limits.

EU ID	Point ID	Horsepower [(1)(2)]	Pollutant	EF (lb/hp-hr)	Emissions	
					lb/hr	TPY
ENG-GFMMB	ENG-GFMMB	135/500	NO_X	0.0151[(5)]	7.6	1.9
			CO	0.0046[(5)]	2.3	0.6
			SO_2	0.0021[(4)]	1.0	0.3
			VOC	0.0005[(5)]	0.2	0.1
			PM_{10}	0.0009[(5)]	0.5	0.1
ENG-E5017	ENG-E5017	484	NO_X	0.0108[(5)]	5.2	1.3
			CO	0.0009[(5)]	0.5	0.1
			SO_2	0.0021[(5)]	1.0	0.2
			VOC	0.0002[(5)]	0.1	0.0
			PM_{10}	0.0002[(5)]	0.1	0.0
ENG-E5018	ENG-E5018	484	NO_X	0.0108[(5)]	5.2	1.3
			CO	0.0009[(5)]	0.5	0.1
			SO_2	0.0021[(5)]	1.0	0.2
			VOC	0.0002[(5)]	0.1	0.0
			PM_{10}	0.0002[(5)]	0.1	0.0
ENG-EPIAB	ENG-EPIAB	200/500	NO_X	0.0079[(5)]	4.0	1.0
			CO	0.0029[(5)]	1.4	0.4
			SO_2	0.0021[(5)]	1.0	0.3
			VOC	0.0079[(5)]	4.0	1.0
			PM_{10}	0.0004[(5)]	0.2	0.0
E-0118	E-0118	600	NO_X	0.0063[(5)]	3.8	0.9
			CO	0.0012[(5)]	0.7	0.2
			SO_2	0.00001[(6)]	0.0	0.0
			VOC	0.0001[(5)]	0.1	0.0
			PM_{10}	0.0002[(5)]	0.1	0.0
E-SPIAB	E-SPIAB	575	NO_X	0.0050[(5)]	2.9	0.7
			CO	0.0039[(5)]	2.2	0.6
			SO_2	0.00001[(6)]	0.0	0.0
			VOC	0.0016[(5)]	0.9	0.2
			PM_{10}	0.0002[(5)]	0.1	0.0
E-37	E-37	755	NO_X	0.0101[(5)]	7.6	1.1
			CO	0.0009[(5)]	0.7	0.4
			SO_2	0.00001[(6)]	0.0	0.0
			VOC	0.0003[(5)]	0.2	0.0
			PM_{10}	0.0005[(5)]	0.4	0.1

EU ID	Point ID	Horsepower [(1)(2)]	Pollutant	EF (lb/hp-hr)	Emissions	
					lb/hr	TPY
SUBTOTALS			**NO_X**	**-**	**36.3**	**8.2**
			CO	**-**	**8.3**	**2.4**
			SO_2	**-**	**4.0**	**1.0**
			VOC	**-**	**5.6**	**1.3**
			PM_{10}	**-**	**1.5**	**0.2**

1. Horsepower is shown for the purposes of regulatory applicability only and is not to be construed as a limit.
2. Emergency generators, fire water pump drivers, and emergency back-up instrument air compressor drivers assumed to operate 500 hrs/yr.
3. Reserved.
4. Based on AP-42 Section 3.3 (10/96).
5. Based on vendor-provided factors.
6. Based on mass balance with sulfur content in fuel.

EUG ENG-5: Non-Emergency CI Engines Subject to 40 CFR Part 60 Subpart IIII

Note: Not all engines operate continuously. TPY emissions are based on actual hours of operation. These engines have no emissions limits.

EU ID	Point ID	Horsepower[(1)]	Pollutant	EF (lb/hp-hr)	Emissions	
					lb/hr	TPY
ENG-4FCCAB	ENG-4FCCAB	140/500[(2)]	NO_X	0.0058[(5)]	2.9	4.2
			CO	0.0026[(5)]	1.3	1.9
			SO_2	0.0021[(4)]	1.0	1.5
			VOC	0.0054[(5)]	2.9	4.2
			PM_{10}	0.0003[(5)]	0.2	0.2
ENG-4FCCCAT	ENG-4FCCCAT	140/500[(2)]	NO_X	0.0058[(5)]	2.9	0.7
			CO	0.0026[(5)]	1.3	0.3
			SO_2	0.0021[(4)]	1.0	0.3
			VOC	0.0054[(5)]	2.9	0.7
			PM_{10}	0.0003[(5)]	0.2	0.0
SUBTOTALS			**NO_X**	**-**	**5.8**	**4.9**
			CO	**-**	**2.6**	**2.2**
			SO_2	**-**	**2.0**	**1.8**
			VOC	**-**	**5.8**	**4.9**
			PM_{10}	**-**	**0.4**	**0.2**

1. Horsepower is shown for the purposes of regulatory applicability only and is not to be construed as a limit.
2. Emissions calculated using 500 hp.
3. Reserved.
4. Based on AP-42 Section 3.3 (10/96).
5. Based on vendor-provided factors.

EUG FCC-1: Fluid Catalytic Cracking Unit Catalyst Regenerators Subject to 40 CFR Part 60 Subpart J and 40 CFR Part 63 Subpart UUU (Refinery MACT II)

EU ID	Point ID	Process Rate (bpd)	Pollutant	Emissions [1]	
				lb/hr[2]	TPY
No. 5 FCCU	No. 5 FCCU	44,000	NO_X	26.4	116.0
			CO	-	-
			SO_2	58.7 / 425[3]	257.0
			VOC	-	-
			PM_{10}	30.0	131.0
SUBTOTALS			**NO_X**	**26.4**	**116.0**
			CO	**-**	**-**
			SO_2	**58.7 / 425[3]**	**257.0**
			VOC	**-**	**-**
			PM_{10}	**30.0**	**131.0**

1. Emissions are based on previous permit limits. No. 5 FCCU emissions shown are for post-control installations (wet gas scrubber and enhanced non-selective catalytic reduction). HTR-5FCC Converter Startup Preheater emissions are included in No. 5 FCCU emissions.
2. 365-day rolling average, except as noted.
3. 1-hour maximum.

EUG FCC-2: Fluid Catalytic Cracking Unit Catalyst Regenerators Subject to 40 CFR Part 60 Subpart Ja and 40 CFR Part 63 Subpart UUU (Refinery MACT II)

EU ID	Point ID	Process Rate (bpd)	Pollutant	Emissions [1]	
				lb/hr[2]	TPY
No. 4 FCCU	No. 4 FCCU	26,000	NO_X	19.9	87.0
			CO	25.1	110.0
			SO_2	12.6	55.0
			VOC	1.9	8.3
			PM_{10}	16.7	73[3] / 110[4]
No. 5 FCCU	No. 5 FCCU	44,000	CO	47.2	206.7
SUBTOTALSN			**NO_X**	**19.9**	**87.0**
			CO	**72.3**	**316.7**
			SO_2	**12.6**	**55.0**
			VOC	**1.9**	**8.3**
			PM_{10}	**16.7**	**110.0**

1. H-6037A/6037B emissions are included in the No. 4 FCCU emissions.
2. 365-day rolling average, except as noted.
3. Non-sulfate PM. Measured using EPA Method 5B.
4. Total PM. Measured using EPA Method 5B and EPA Method 202 or alternative.

EUG CRU-1: Catalytic Reforming Unit Catalyst Regenerator Vents Subject to 40 CFR Part 63 Subpart UUU (Refinery MACT II)

EU ID	Point ID	Process	Emissions (1)	
			lb/hr	TPY
No. 2 CRU	Flare-CC	Initial catalyst depressuring and catalyst purging	0.0	0.0
No. 3 CRU	Flare-EP	Initial catalyst depressuring and catalyst purging	0.0	0.0
SUBTOTALS			**0.0**	**0.0**

1. There are no emissions from the No. 2 and No. 3 CRU Regenerator Vents because they are routed back to process by the Flare-CC flare gas recovery unit and Flare-EP flare gas recovery unit, respectively.

EUG FLR-1: Flares Subject to 40 CFR Part 60 Subpart Ja

EU ID	Point ID	Process Rate (MMBtu/hr)	Pollutant	EF (lb/MMBtu)	Emissions (1)	
					lb/hr	TPY
Flare-CC (3)	Flare-CC	24.4	NO_X	0.0485	1.2	5.2
			CO	0.350	8.5	37.4
			SO_2	(2)	16.3	71.5
			VOC	0.063	1.5	6.7
			PM_{10}	-	0.0	0.0
Flare-CF (3)	Flare-CF	3.9	NO_X	0.0485	0.2	0.8
			CO	0.350	1.4	6.0
			SO_2	(2)	0.0	0.0
			VOC	0.063	0.2	1.1
			PM_{10}	-	0.0	0.0
Flare-EP (3)	Flare-EP	10.7	NO_X	0.0485	0.5	2.3
			CO	0.350	3.8	16.5
			SO_2	(2)	2.9	12.7
			VOC	0.063	0.7	3.0
			PM_{10}	-	0.0	0.0
Flare-SP (3)	Flare-SP	24.4	NO_X	0.0485	1.2	5.2
			CO	0.350	8.6	37.5
			SO_2	(2)	7.5	32.7
			VOC	0.063	1.5	6.7
			PM_{10}	-	0.0	0.0
SUBTOTALS			**NO_X**	**-**	**3.1**	**13.5**
			CO	**-**	**22.3**	**97.4**
			SO_2	**-**	**26.7**	**116.9**
			VOC	**-**	**3.9**	**17.5**
			PM_{10}	**-**	**0.0**	**0.0**

1. Does not include process upset and other non-routine flaring emissions. VOC emissions from EUG VNT-1, EUG VNT-2, and EUG CRU-1 are included.
2. Flare SO_2 emissions are calculated using a stoichiometric conversion of all H_2S to SO_2.
3. Flare gas recovery units (FGRU) have been installed to recover some waste streams routed to the Flare-CF, Flare-CC, Flare-EP, and Flare-SP.

EUG LOD-1: Reserved

EUG LOD-2: Loading Racks Subject to Oklahoma Rules or Permit Requirements

EU ID	Point ID	Process	Throughput (gal/yr)	VOC Emissions	
				lb/hr	TPY
Load-SP	Load-SP	South Plant Loading Rack (Distillates)	175,200,000	3.0	8.8

EUG LOD-3: Insignificant Activity Loading Racks

Emissions estimates for individual insignificant activities are not necessary since facility is already a Title V major source.

EUG VNT-1: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 1 Miscellaneous Process Vents

EU ID	Point ID	Process	VOC Emissions (1)	
			lb/hr	TPY
VNT-D0749	Flare-CC	D-749 Merox disulfide separator drum	0.0	0.0

1. Emissions are included in EUG FLR-1.

EUG VNT-2: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 2 Miscellaneous Process Vents

EU ID	Point ID	Process	VOC Emissions	
			lb/hr	TPY
VNT-D0701	VNT-D0701	D-701 vent/drain to atmosphere	3.0	13.1
VNT-D0702	VNT-D0702	D-702 vent/drain to atmosphere	3.0	13.1
VNT-D0704	VNT-D0704	D-704 vent/drain to atmosphere	3.0	13.1
VNT-D0714	VNT-D0714	D-714 vent/drain to atmosphere	3.0	13.1
VNT-D0717 (1)	Flare-CC	D-717 depropanizer overhead reflux	0.0	0.0
VNT-D0741 (1)	Flare-CC	D-741 ASO/KOH separator	0.0	0.0
VNT-D0748 (1)	Flare-CC	D-748 fuel gas drum	0.0	0.0
VNT-D5173	VNT-D5173	D-5173 vent/drain to atmosphere	3.0	13.1
VNT-Load SF LPG	VNT-Load SF	Loading vent line purge to atmosphere	3.6	16.0
VNT-Load SF Toluene	VNT-Load SF Toluene	Toluene unloading line vent to atmosphere	3.0	13.1
VNT-Load SP LPG	VNT-Load SP	Loading and vent line purge to atmosphere	4.2	18.3
VNT-T0256 (1)	Flare-CC	Alky flare slop tank vent	0.0	0.0
VNT-W0193(1)	Flare-CC	W-193 overhead non-condensables	0.0	0.0
VNT-D0452	VNT-D0452	D-452 vent/drain	0.9	4.1
SUBTOTALS			**26.7**	**117.0**

1. Emissions are included in EUG FLR-1.

EUG VNT-3: Reserved

EUG VNT-4: 40 CFR Part 63 Subpart GGGGG (Site Remediation MACT) Process Vents

EU ID	Point ID	Process	Pollutant	Emissions	
				lb/hr	TPY
VNT-SVE	VNT-SVE	Soil Vapor Extraction (SVE) Vent	VOC	4.5	19.9

EUG VNT-5: Insignificant Activity Atmospheric Process Vents

Emissions estimates for individual insignificant activities are not necessary since facility is already a Title V major source.

EUG VNT-6: Equipment Subject to the Maintenance Vent Provisions of 40 CFR Part 63, Subpart CC (Refinery MACT I)

EU ID	Point ID	Process	Pollutant	Emissions	
				lb/hr	TPY
Refinery-Wide Maintenance Vents	Refinery-Wide Maintenance Vents	Any process vent used as a result of startup, shutdown, maintenance, or inspection of equipment	VOC	4.1	18.0

EUG FUG-1: Fugitive Piping Equipment Leaks Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) and/or 40 CFR Part 60 Subpart GGGa

EU ID	Point ID	Equipment LL = Light Liquid HL = Heavy Liquid	Approx. Number of Items	Emission Factor, lb/hr-source	VOC Emissions	
					lb/hr	TPY
Refinery-Wide Piping Equipment Fugitive Leaks	Refinery-Wide Piping Equipment Fugitive Leaks	Gas Valves	24,727	0.00253	62.6	274.2
		LL Valves	28,698	0.00468	134.3	588.2
		HL Valves	17,928	0.00051	9.1	40.0
		Flanges	241,302	0.00013	31.4	137.5
		LL Pump Seals	393	0.04509	17.7	77.5
		HL Pump Seals	427	0.04718	20.1	88.2
		Gas Compressors	20	0.50265	10.1	44.0
		Gas Relief Valves to Atm	14	0.22928	3.2	14.1
		Gas Relief Valves to Flare	509	0.00459	2.3	10.2
		Sample Stations	606	0.03307	20.0	87.8
SUBTOTALS					**310.0**	**1,361.7**

EUG FUG-2: Fugitive Oily Water Sewer System Component Leaks Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) and 40 CFR Part 61 Subpart FF (Benzene Waste Operations)

EU ID	Point ID	Equipment	Approx. Number of Items	Emission Factor, lb/hr-source	VOC Emissions	
					lb/hr	TPY
FUG-Coker ORU	FUG-CC	Process drains	27	0.035	0.9	4.1
		Junction boxes/sumps/WDB	6	0.07	0.4	1.8
FUG-1HP, 2HP, 2Isom, 8HDT, 9HDT, BFU & FGRU	FUG-CF	Process drains	147	0.035	5.1	22.3
		Junction boxes/sumps/WDB	52	0.07	3.6	15.9
FUG-2CTU, 3CRU, 4FCC & ORU	FUG-EP	Process drains	177	0.035	6.2	27.1
		Junction boxes/sumps/WDB	33	0.07	2.3	10.1
FUG-1SWS	FUG-SP	Process drains	10	0.035	0.4	1.5
		Junction boxes/sumps/WDB	1	0.07	0.1	0.3
FUG-2SWS	FUG-SP	Process Drains	11	0.035	0.4	1.7
		Junction boxes/sumps/WDB	0	0.07	0	0
FUG-WP ORU	FUG-WP	Process drains	19	0.035	0.7	2.9
		Junction boxes/sumps/WDB	8	0.07	0.6	2.5
FUG-OM Tank Farm & WWTS	FUG-OM	Process drains	0	0.035	0.0	0.0
		Junction boxes/sumps/WDB	27	0.07	1.9	8.3
FUG-SP Tank Farm	FUG-SP	Process drains	0	0.035	0.0	0.0
		Junction boxes/sumps/WDB	3	0.07	0.2	0.9
FUG-6HDT	FUG-CC	Process drains	13	0.035	0.5	2.0
		Junction boxes/sumps/WDB	12	0.07	0.8	3.7
FUG-TOP	FUG-WP	Process drains	4	0.035	0.1	0.6
		Junction boxes/sumps/WDB	1	0.07	0.1	0.3
FUG-DEC3	FUG-CC	Process drains	4	0.035	0.1	0.4
		Junction boxes/sumps/WDB	1	0.07	0.1	0.3
SUBTOTALS					**24.5**	**106.7**

EUG FUG-3: Fugitive Oily Water Sewer System Component Leaks Subject to 40 CFR Part 60 Subpart QQQ

EU ID	Point ID	Equipment	Approx. Number of Items	Emission Factor, lb/hr-source	VOC Emissions (1)	
					lb/hr	TPY
FUG-7HDT	FUG-WP	Process drains	29	0.035	-	-
		Junction boxes/sumps/WDB	13	0.07	-	-
SUBTOTALS					**-**	**-**

1. Emissions from certain units have already been included in EUG FUG-2 so they are not shown in this table.

EUG FUG-4: Fugitive Oily Water Sewer System Component Leaks Subject to 40 CFR Part 61 Subpart FF (Benzene Waste Operations) Exemption Recordkeeping Requirements

EU ID	Point ID	Equipment	Approx. Number of Items	Emission Factor, lb/hr-source	VOC Emissions	
					lb/hr	TPY
Refinery-Wide Oily Water Sewer Component Fugitive Leaks	Refinery-Wide Oily Water Sewer Component Fugitive Leaks	Process drains (controlled)	78	0.035	2.7	12.0
		Process drains (uncontrolled)	2,118	0.07	148.3	649.4
		Closed drains	243	0.0	0.0	0.0
		Junction boxes/sumps (controlled)	0	0.07	0.0	0.0
		Junction boxes/sumps (uncontrolled)	303	0.47	142.4	623.8
SUBTOTALS					**293.4**	**1,285.1**

EUG FUG-5: Reserved

EUG FUG-6: Cooling Tower Fugitive Sources Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I)

EU ID	Point ID	Recirculation Rate (gpm)	Pollutant	EF (lb/MMgal)	Emissions	
					lb/hr	TPY
Y-0002	Y-0002	15,600	VOC	0.7	0.7	2.9
			PM_{10}	-	6.4	28.0
Y-0002 A	Y-0002 A	15,000	VOC	0.7	0.6	2.8
			PM_{10}	-	6.2	27.0
Y-0003	Y-0003	19,000	VOC	0.7	0.9	3.5
			PM_{10}	-	5.9	25.8
Y-0005	Y-0005	34,000	VOC	0.7	1.4	6.25
			PM_{10}	-	10.9	47.9
Y-0006	Y-0006	11,406	VOC	0.7	0.8	2.1
			PM_{10}	-	6.1	26.8

EU ID	Point ID	Recirculation Rate (gpm)	Pollutant	EF (lb/MMgal)	Emissions	
					lb/hr	TPY
Y-0007	Y-0007	6,000	VOC	0.7	0.25	1.10
			PM_{10}	-	0.60	2.63
Y-0010	Y-0010	22,282	VOC	0.7	0.9	4.1
			PM_{10}	-	3.1	13.8
Y-6026	Y-6026	14,000	VOC	0.7	0.6	2.6
			PM_{10}	-	4.4	19.1
Y-6027	Y-6027	14,000	VOC	0.7	0.6	2.6
			PM_{10}	-	3.7	16.0
Y-8000	Y-8000	7,500	VOC	0.7	0.3	1.4
			PM_{10}	-	2.6	11.6
SUBTOTALS			**VOC**	**-**	**7.1**	**29.4**
			PM_{10}	**-**	**49.9**	**218.6**

EUG FUG-6.1: Insignificant Cooling Tower Fugitive Sources

EU ID	Point ID	Recirculation Rate (gpm)	Pollutant	EF (lb/MMgal)	Emissions	
					lb/hr	TPY
Y-0009	Y-0009	500	VOC	-	0.0	0.0
			PM_{10}	-	0.1	0.3
SUBTOTALS			**VOC**	**-**	**0.0**	**0.0**
			PM_{10}	**-**	**0.1**	**0.3**

EUG FUG-7: Materials Handling Fugitive Sources Subject to Oklahoma Rules or Permit Requirements

EU ID	Point ID	Process Rate (TPY)	PM_{10} Emissions	
			lb/hr	TPY
Coke Handling Facility	Coke Handling Facility	475,000	2.7	8.8

EUG FUG-8: Insignificant Activity Fugitive Sources

Emissions estimates for individual insignificant activities are not necessary since facility is already a Title V major source.

EUG COK-1: Delayed Cokers Subject to 40 CFR Part 60 Subpart Ja and 40 CFR Part 63 Subpart CC

EU ID	Point ID	Pollutant	Emissions	
			lb/hr	TPY
No. 7 Coker Unit	Coke Drum Operations	VOC	5.0	22.0
		$PM_{10/2.5}$	0.7	3.0
		H_2S	0.9	4.0

EUG FW: Facility-Wide Applicable Requirements

Summary of Potential Emissions

EUG	NO_X		CO		SO_2		VOC		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
EUG TNK-1	--	--	--	--	--	--	37.8	165.6	--	--
EUG TNK-2	--	--	--	--	--	--	48.9	215.1	--	--
EUG TNK-3	--	--	--	--	--	--	90.5	400.0	--	--
EUG TNK-4	--	--	--	--	--	--	84.5	369.2	--	--
EUG TNK-5	--	--	--	--	--	--	8.7	38.2	--	--
EUG TNK-6	--	--	--	--	--	--	0.0	0.1	--	--
EUG TNK-7	--	--	--	--	--	--	0.2	1.3	--	--
EUG TNK-8	--	--	--	--	--	--	--	--	--	--
EUG HTR-1	56.9	250.0	73.0	319.6	37.9	165.5	7.1	31.0	9.8	43.2
EUG HTR-2	178.6	738.5	128.2	561.8	61.9	271.5	12.2	53.0	16.8	75.5
EUG HTR-2.1	28.9	126.5	26.2	144.6	12.5	54.7	3.7	15.9	5.1	22.0
EUG HTR-2.2	8.4	36.7	7.1	30.9	0.1	0.2	0.5	2.0	0.6	2.8
EUG HTR-3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EUG HTR-4	--	--	--	--	--	--	--	--	--	--
EUG ENG	--	--	--	--	--	--	--	--	--	--
EUG ENG-1a	25.5	111.8	3.1	13.6	0.0	0.0	1.0	4.2	0.4	1.4
EUG ENG-1b	17.6	4.4	4.0	1.0	1.5	0.4	0.5	0.1	0.5	0.1
EUG ENG-2	65.0	16.2	14.0	3.5	4.7	1.1	4.8	1.2	4.5	1.1
EUG ENG-3	0.4	2.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0
EUG ENG-4	36.3	8.2	8.3	2.4	4.0	1.0	5.6	1.3	1.5	0.2
EUG ENG-5	5.8	4.9	2.6	2.2	2.0	1.8	5.8	4.9	0.4	0.2
EUG FCC-1	26.4	116.0	--	--	58.7	275.0	--	--	30.0	131.0
EUG FCC-2	19.9	87.0	72.3	316.7	12.6	55.0	1.9	8.3	16.7	110.0
EUG CRU-1	--	--	--	--	--	--	--	--	--	--
EUG FLR-1	3.1	13.5	22.3	97.4	26.7	116.9	3.9	17.5	--	--
EUG LOD-1	--	--	--	--	--	--	--	--	--	--
EUG LOD-2	--	--	--	--	--	--	3.0	8.8	--	--
EUG LOD-3	--	--	--	--	--	--	--	--	--	--
EUG VNT-1	--	--	--	--	--	--	--	--	--	--
EUG VNT-2	--	--	--	--	--	--	26.7	117.0	--	--
EUG VNT-3	--	--	--	--	--	--	--	--	--	--
EUG VNT-4	--	--	--	--	--	--	4.5	19.9	--	--
EUG VNT-5	--	--	--	--	--	--	--	--	--	--
EUG VNT-6	--	--	--	--	--	--	4.1	18.0	--	--
EUG FUG-1	--	--	--	--	--	--	310.0	1361.7	--	--
EUG FUG-2	--	--	--	--	--	--	24.5	106.7	--	--
EUG FUG-3	--	--	--	--	--	--	--	--	--	--
EUG FUG-4	--	--	--	--	--	--	293.4	1285.1	--	--
EUG FUG-5	--	--	--	--	--	--	--	--	--	--
EUG FUG-6	--	--	--	--	--	--	7.1	29.4	49.9	218.6
EUG FUG-6.1	--	--	--	--	--	--	--	--	0.1	0.3
EUG FUG-7	--	--	--	--	--	--	--	--	2.7	8.8
EUG FUG-8	--	--	--	--	--	--	--	--	--	--
EUG COK-1	--	--	--	--	--	--	5.0	22.0	0.7	3.0
EUG FW	--	--	--	--	--	--	--	--	--	--
Totals	**472.8**	**1,515.7**	**361.1**	**1,494.1**	**222.6**	**943.1**	**995.9**	**4,297.5**	**139.7**	**618.2**

EUG	NO_X		CO		SO_2		VOC		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Previous[1]	**447.9**	**1,406.4**	**371.3**	**1,291.9**	**220.2**	**914.6**	**994.4**	**4,287.6**	**139.4**	**580.2**
Change	**24.9**	**109.3**	**-10.2**	**202.2**	**2.4**	**28.5**	**1.5**	**9.9**	**0.3**	**38.0**

1. From Permit No. 2012-704-C (M-11).

X.2 Hazardous Air Pollutants (HAP)

Total emissions of HAP from the Ponca City Refinery as reported in the 2022 annual emissions inventory are shown as follows. Sources of HAP include storage tanks, piping component fugitive leaks, loading racks, sewer component fugitive leaks, API separators, toluene unloading, cooling towers, atmospheric vents, combustion of fuel, and the land farm. HAP emission calculations are based on sample data, AP-42 factors, process knowledge, or engineering calculations.

HAP Name	TPY
Lead	0.009
Ammonia	5.500
1,3-Butadiene	0.020
2,2,4-Trimethylpentane	0.324
Acetaldehyde	0.314
Acrolein	0.328
Antimony	0.006
Arsenic	0.002
Benzene (including benzene from gasoline)	6.454
Biphenyl	0.245
Cadmium	0.014
Chromium	0.022
Cobalt	0.005
Cresols/Cresylic acid (isomers and mixture)	0.126
Cumene	0.164
Cyanide	35.182
Ethyl benzene	3.103
Formaldehyde	1.785
Hexane	31.318
Hydrochloric acid	1.006
Hydrogen sulfide	3.172
Manganese	0.009
Mercury	0.002
Methanol	3.452
Methyl tert butyl ether	0.038
Naphthalene	2.798
Nickel	0.053
Phenol	0.374
PolycyclicOrganic Matter	12.825
Selenium	0.013

HAP Name	TPY
Styrene	0.251
Toluene	20.959
Xylenes (isomers and mixture)	15.410
TOTAL	**145.283**

X.3 Greenhouse Gases (GHG)

The applicant has presented estimates of emissions of GHG at this facility that demonstrate that it is a PSD-major source, with PTE of 2,793,555.4 TPY CO_2-equivalent.

SECTION XI. INSIGNIFICANT ACTIVITIES

The insignificant activities identified in the current Title V operating permit and listed in OAC 252:100-8, Appendix I, are shown below. Recordkeeping for activities indicated with "*" is listed in the Specific Conditions. Some insignificant activities listed below were not operational at the time of the application. Other future activities that qualify as insignificant activities per OAC 252:100-8 Appendix I, which are not specifically listed below, may be conducted in the future without notification to DEQ. Any activity subject to an NSPS or NESHAP standard or state requirement is not insignificant. The permittee will be required to maintain records that demonstrate the activity is an insignificant activity.

- Space heaters, boilers, process heaters and emergency flares less than or equal to 5 MMBtu/hr heat input (commercial natural gas). The facility currently operates three natural gas-fired boilers that meet these criteria.

- Emissions from fuel storage/dispensing equipment operated solely for facility owned vehicles if fuel throughput is not more than 2,175 gallons/day, averaged over a 30-day period.

- * Emissions from storage tanks constructed with a capacity less than 39,894 gallons which store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature.

- Additions or upgrades of instrumentation or control systems that result in emissions increases less than the pollutant quantities specified in OAC 252:100-8-3(e)(1).

- Cold degreasing operations utilizing solvents that are denser than air. These are part of facility maintenance operations, which is a "trivial activity." Therefore, no recordkeeping is required.

- Welding and soldering operations utilizing less than 100 pounds of solder and 53 tons per year of electrodes. These are conducted as part of facility maintenance including turnarounds and new construction, which is a "trivial activity"; therefore, no recordkeeping is required.

- Torch cutting and welding of less than 200,000 tons of steel fabricated. These are conducted as part of facility maintenance including turnarounds and new construction, which is a "trivial activity"; therefore, no recordkeeping is required.

- Site restoration and/or bioremediation activities of <5 years expected duration.

- Hydrocarbon-contaminated soil aeration pads utilized for soils excavated at the facility only.

- Emissions from operation of groundwater remediation wells including but not limited to emissions from venting, pumping, and collecting activities subject to de minimis limits for air toxics (OAC 252:100-41-43) and HAPs (Section 112(b) of CAAA90).

- Hazardous waste and hazardous materials drum staging areas. The facility includes a staging area for drummed hazardous wastes.

- Sanitary sewage collection and treatment facilities other than incinerators and Publicly Owned Treatment Works (POTW). Stacks or vents for sanitary sewer plumbing traps are also included (i.e., lift station).

- Emissions from landfills and land farms unless otherwise regulated by an applicable state or federal regulation.

- Surface coating operations that do not exceed a combined total usage of more than 60 gallons/month of coatings/thinners, and clean-up solvents at any one emission unit. These are conducted as part of facility maintenance, which is a "trivial activity"; therefore, no recordkeeping is required.

- Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas.

- Hand wiping and spraying of solvents from containers with less than 1-liter capacity used for spot cleaning and/or degreasing in ozone attainment areas. This is conducted as part of facility maintenance, which is a "trivial activity"; therefore, no recordkeeping is required.

- * Activities having the potential to emit no more than 5 TPY (actual) of any criteria pollutant.

SECTION XII. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory obligations to incorporate into the permit.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards. This subchapter applies to EUG-FW for facility-wide applicable requirements; however, there are no obligations to incorporate into the permit.

OAC 252:100-5 (Registration, Emission Inventory, and Annual Fees) [Applicable]
The owner or operator of any facility that is a source of air emissions shall submit a complete emission inventory annually on forms obtained from the Air Quality Division. Emission inventories have been submitted and fees paid for previous years as required. The requirements from this subchapter have been incorporated into the Standard Conditions of the permit and apply to EUG-FW for facility-wide applicable requirements.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification or construction permit. Insignificant activities mean individual emission units that either are on the list in Appendix I (OAC 252:100), or whose actual calendar year emissions do not exceed the following limits:

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for single HAP that the EPA may establish by rule

Emissions and operating limitations have been established from the application or previous construction and operating permits. After construction, this modification will be incorporated into the facility's Title V permit. The requirements of Subchapter 8 have been incorporated into the Major Source Standard Conditions of the permit and apply to EUG-FW for facility-wide applicable requirements.

Part 7 covers the PSD requirements for attainment areas. Under OAC 252:100-8-31, a major modification is defined as any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant and a significant net emissions increase of that pollutant. The project included physical modifications which resulted in a significant emissions increase and a significant net emissions increase of CO and GHG emissions. As a result, BACT analyses and ambient air impacts modeling demonstrations were required. The project did not result in a significant emissions increase and a significant net emissions increase for any other pollutants.

Emission increases resulting from the project in this permit were calculated on a pollutant-by-pollutant basis using the tests described in OAC 252:100-8-30(b)(3) through OAC 252:100-8-30(b)(6). As such, the Ponca City Refinery will be subject to the monitoring and recordkeeping requirements of OAC 252:100-8-36.2(c)(3). Because the 2020-2022 LRP Project will increase permitted limits, and so the potential to emit, of heaters H-0003, H-0004, and H-0011, the

monitoring and recordkeeping required by OAC 252:100-8-36.2(c)(3) must be maintained for 10 years following resumption of regular operations after completion of the proposed project.

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for mitigation, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63. The requirements from this subchapter have been incorporated into the Standard Conditions of the permit and apply to EUG-FW for facility-wide applicable requirements.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter) [Applicable]
This subchapter specifies particulate emission limits for fuel-burning equipment and industrial processes. Indirect-fired equipment includes process heaters and steam boilers. Industrial processes at the facility are fluid catalytic cracking unit regenerators, cooling towers, and coke loading facility. The following table compares allowable PM emissions to actual or calculated emissions. All units are in compliance with Subchapter 19. Applicable limitations from this subchapter are incorporated into the permit under individual EUGs.

COMPARISON OF PM EMISSIONS TO ALLOWABLE EMISSION RATES UNDER OAC 252:100 APPENDIX G

Unit	Process Weight, TPH (1)	Allowable PM Emissions, lb/hr	Actual PM Emission Rate, lb/hr
No. 5 FCCU	1,944	86.5	58.6
No. 4 FCCU	833	75.3	63.2
Cooling Towers, each	<6,255	104	1.30
Coke Loading Facility	120	53.1	9.9

1. The process weights for FCCUs are the catalyst circulation rates measured during stack testing.

COMPARISON OF PM EMISSION RATES TO ALLOWABLE EMISSION RATES UNDER OAC 252:100 APPENDIX C

Process Unit	Maximum Heat Input, MMBtu/hr (1), (2)	Allowable PM Emission Rate, lb/MMBtu	AP-42-based PM Emission Rate, lb/MMBtu (3)
Natural Gas-Fired Heaters and Boilers, each	<1,000	0.20	0.007

Process Unit	Maximum Heat Input, MMBtu/hr (1), (2)	Allowable PM Emission Rate, lb/MMBtu	AP-42-based PM Emission Rate, lb/MMBtu (3)
Diesel-Fired Boilers, each	<10	0.60	0.015
Gasoline-Fired Engines <600 hp, each	<10	0.60	0.10
Diesel-Fired Engines <600 hp, each	<10	0.60	0.31
Diesel-Fired Engines ≥600 hp, each	<10	0.60	0.057
Natural Gasoline-Fired Engine, each	<10	0.60	0.048

1. All facility natural gas-fired heaters and boilers are less than 1,000 MMBtu/hr. Diesel-fired boilers are less than 10 MMBtu/hr. Gasoline-, diesel-, and natural gasoline-fired engines are less than 10 MMBtu/hr.
2. For engines, an average brake-specific fuel consumption of 7,000 Btu/hp-hr was used to convert from horsepower to MMBtu/hr.
3. For diesel-fired boilers, a fuel heating value of 0.137 MMBtu/gal was used to convert gallons to Btu.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity.

This subchapter requires owners or operators of the following emission sources to install, calibrate, operate, and maintain all monitoring equipment necessary for continuously monitoring opacity:

1. Fluid bed catalytic cracking unit catalyst regenerators at petroleum refineries as specified in paragraph 2.4 of 40 CFR Part 51, Appendix P; and
2. Fossil fuel-fired steam generators with a design heat input value of 250 MMBtu/hr or more and that does not burn gaseous fuel exclusively; and
3. Any fuel-burning equipment with a design heat input value of 250 MMBtu/hr or more that does not burn gaseous fuel exclusively, and that was not being on or before July 1, 1972, or that is modified after July 1, 1972.

The No. 4 FCCU will comply with the requirements of 40 CFR §60.105a(b)(1) for units controlled using a wet scrubber. An alternative monitoring method approval request was submitted to EPA on April 18, 2007, for the No. 5 FCCU in lieu of opacity monitoring, due to the installation of a wet gas scrubber. For other equipment, the requirements from this subchapter have been incorporated into the Standard Conditions of the permit and apply to EUG-FW for facility-wide applicable requirements.

OAC 252:100-29 (Fugitive Dust) [Applicable]
Subchapter 29 prohibits the handling, transportation, or disposition of any substance likely to become airborne or windborne without taking "reasonable precautions" to minimize emissions of fugitive dust. No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to

interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. Measures that may be taken at the facility as necessary to reduce dust is watering of dirt roads, stockpiles, and transport loads, and planting of vegetation. These measures achieve compliance with the "reasonable precautions" requirement. The requirements from this subchapter have been incorporated into the Standard Conditions of the permit and apply to EUG-FW for facility-wide applicable requirements.

OAC 252:100-31 (Sulfur Compounds) [Applicable]

Part 2, Part 31-7 limits the ambient air concentration of hydrogen sulfide (H_2S) emissions from any new or existing source to 0.2 ppmv (24-hour average), which is equivalent to 283 $\mu g/m^3$ (based on EPA standard conditions). Phillips 66 submitted modeling to demonstrate compliance with the H_2S ambient air concentration limit of this part for Permit No. 2012-704-TVR. H_2S sources from the Ponca City Pipeline Activities were considered in the H_2S modeling submittal for Permit No. 2012-704-TVR. The modeled maximum 24-hour ground level concentration was modeled to be 45.48 $\mu g/m^3$. For additional details, see the Memorandum of Permit No. 2012-704-TVR. Jupiter Sulfur submitted H_2S modeling as part of the application for Permit No. 2022-0436-TV. The modeled maximum 24-hour ground level concentration for Jupiter Sulfur was 276 $\mu g/m^3$. AQD conducted a review by combining the previously submitted H_2S modeling from both the Refinery and the Jupiter Sulfur facility. The modeled ambient air maximum 24-hour ground level concentration for the combined facilities was 269 $\mu g/m^3$. Therefore, the H_2S emissions from the refinery as presented in the modeling analysis do not result in a modeled violation of the H_2S the limit contained in OAC 252:100-31-7(b).

Part 5, Section 31-26 limits sulfur dioxide emissions from new fuel-burning equipment (constructed or modified after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBtu heat input averaged over 3 hours. All gas-fired equipment at the Refinery combusts fuel gas that meets the fuel gas sulfur standards of NSPS Subpart J. Subpart J specifies a more stringent limit of 0.1 grains/dscf (160 ppm at 60°F). A limit of 0.1 grains/dscf of H_2S in the fuel gas is equivalent to a maximum SO_2 emission rate of 0.031 lb/MMBtu using a fuel higher heating value of 867 Btu/scf. For liquid fuel-fired equipment, the limit is 0.8 lb/MMBtu heat input averaged over 3 hours. EPA's AP-42 factor for diesel-fired engines is 0.29 lb/MMBtu. The factor for diesel-fired heaters and boilers is 0.0016 lb/MMBtu; using a conversion of 0.137 MMBtu/gal of diesel and a typical maximum sulfur specification of 0.15 weight percent. Both factors are less than the limit in this subchapter. The sulfur dioxide limitations for gas-fired equipment are incorporated into the Standard Conditions of the permit. Other applicable limitations from this Part are incorporated into the permit under individual EUGs.

Part 5, Section 31-26 also limits hydrogen sulfide emissions from new petroleum or natural gas process equipment (constructed or modified after December 31, 1974). Removal of hydrogen sulfide in the exhaust stream, or oxidation to sulfur dioxide, is required unless hydrogen sulfide emissions would be less than 0.3 lb/hr for a two-hour average. Hydrogen sulfide emissions shall be reduced by a minimum of 95% of the hydrogen sulfide in the exhaust gas. Direct oxidation of hydrogen sulfide is allowed for units whose emissions would be less than 100 lb/hr of sulfur dioxide for a two-hour average. Nearly 100% of the facility's produced H_2S is recovered in the refinery amine regenerator acid gas streams and then sent to the Jupiter facility neighboring the

refinery. The remaining H_2S is recovered in the Sour Water Stripper overhead gas, which is sent to the Jupiter facility.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter applies to stationary sources that are fuel-burning equipment, constructed, altered, replaced, or rebuilt after February 14, 1972, with a rated heat input greater than or equal to 50 MMBtu/hr. Gas-fired equipment is limited to emissions of 0.20 lbs of NO_X per MMBtu, 3-hour average. The gas-fired heaters and boilers at the facility with heat inputs greater than or equal to 50 MMBtu/hr that were constructed, altered, replaced, or rebuilt after February 14, 1972, are subject to this subchapter. Compliance with the limit is demonstrated by using continuous emission monitors, stack testing, or AP-42 factors. All gas-fired refinery heaters and boilers subject to this subchapter have an anticipated NO_X emission rate of less than or equal to 0.20 lb/MMBtu during normal operations. Liquid fuel-fired equipment is limited to emissions of 0.30 lb of NO_X per MMBtu, 3-hour average. EPA's AP-42 factors are used to estimate emissions from liquid fuel-fired engines, boilers and heaters. The facility does not operate liquid fuel-fired heaters, boilers, or engines with a heat input greater than or equal to 50 MMBtu/hr. The applicable limitations from this subchapter are incorporated into the permit under individual EUGs.

OAC 252:100-35 (Carbon Monoxide) [Applicable]
Subchapter 35 affects petroleum catalytic cracking units and catalytic reforming units installed or modified on or after July 1, 1972. Subchapter 35 requires "complete" secondary combustion, which is defined in the rule as removal of 93% or more of the CO generated. AP-42 (4/15) Table 5.1-1 specifies CO emissions of 13,700 lb/Mbbl for an uncontrolled FCCU.

The No. 4 FCCU was built in 1951. The No. 4 FCCU Yield Improvements and Reliability item is not expected to result in an increase in CO emissions. Nevertheless, the average CO emission for the unit since June 1, 2002, was 19.5 lb/Mbbl, resulting in a 99.86% reduction of CO, and the maximum 1-day average was 293 lb/Mbbl, resulting in a 97.86% reduction of CO. Testing of the No. 4 FCCU (November 2015) showed CO emissions of 10.6 lb/Mbbl, or a 99.9% reduction in CO.

The No. 5 FCCU was built in 1952, but modifications occurring between 1972 and 1973 increased CO emissions; therefore, Subchapter 35 applies to the No. 5 FCCU. The No. 5 FCCU Waste Heat Boiler Replacement project increased CO emissions further. The new shell-and-tube exchanger was installed in September of 2023 and the unit started up in November of 2023 following a turnaround. The average CO emissions for the unit from March 1, 2024, through January 1, 2025 (excluding down time prior to March 1, 2024) when operating the new waste heat exchanger was 8.4 lb/Mbbl (99.93% reduction), with a maximum emission rate: 20.1 lb/Mbbl (99.85% reduction), and an average 24-hr emission rate of 14.2 lb/Mbbl (99.90% reduction).

Applicable requirements from this subchapter are incorporated into the Ponca City Refinery's current Title V permit.

The CRUs located at the facility were in operation prior to the effective date of this rule and have not been modified so as to increase the CO emissions. Therefore, this subpart does not apply to the CRUs.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 3, Section 37-15 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. Part 3 also requires storage tanks constructed after December 28, 1974, with a capacity of more than 40,000 gallons and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a either an external floating roof, a fixed roof with an internal floating cover, a vapor recovery system, or other equally effective control methods approved by the DEQ. Tanks subject to the equipment standards of NSPS, Subparts K, Ka, or Kb are exempt from these requirements.

The facility operates tanks that were constructed after 1974, have a capacity of 400 gallons or more, store a VOC with a vapor pressure greater than 1.5 psia, and are not subject to the equipment standards of NSPS Subparts K, Ka, or Kb. These tanks comply with Subchapter 37 by having submerged fill piping. Applicable requirements from this subchapter are incorporated into the Specific Conditions of the permit and apply to tanks meeting the applicability criteria under individual EUGs.

Part 3, Section 37-16 applies to VOC loading facilities constructed after December 24, 1974. Facilities with a throughput greater than 40,000 gallons/day are required to be equipped with a vapor-collection and disposal system unless all loading is accomplished by bottom loading with the hatches of the tank truck or trailer closed. LOAD-SF has the potential to load more than 40,000 gallons per day, but is exempt from these requirements because it is subject to NSPS Subpart XX per MACT Subpart CC.

Part 5, Section 37-25 limits the VOC content of coating operations. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt.

Part 7, Section 37-35 requires all VOC gases from a vapor recovery blowdown system to be burned by a smokeless flare or equally effective control device unless it is inconsistent with the "Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline" or any State of Oklahoma regulatory agency. Unless it is unreasonable to do so, VOC gases from vapor blowdown systems during non-routine maintenance, startups, shutdowns or malfunctions are burned by refinery flares designed to be smokeless. The requirements from Part 7 are incorporated into the permit under EUG-FW for facility-wide applicable requirements.

Part 7, Section 37-36 requires fuel-burning and refuse-burning equipment is to be operated and maintained so as to minimize emissions of VOCs. Temperature and available air must be sufficient to provide essentially complete combustion. This rule applies to facility heaters and boilers in constructed or modified after December 24, 1974. The facility operates equipment that was constructed or modified after December 24, 1974 which is subject to this rule. The equipment is operated and maintained according to standard operating procedures or according to manufacturer's recommendations. The requirements from this part are incorporated into the permit under individual EUGs for heaters, boilers and engines.

Part 7, Section 37-37 requires all effluent water separators' openings or floating roofs to be sealed or equipped with an organic vapor recovery system. The open API traps at the facility were constructed or modified prior to the effective date for existing equipment, so this part does not apply to the open API traps.

OAC 252:100-40 (Friable Asbestos) [Applicable]
This rule contains friable asbestos requirements (in addition to the asbestos requirements of 40 CFR Part 61). The facility is subject to this requirement since it handles and stores friable asbestos from demolition/renovation activities. The requirements from this subchapter are incorporated into the permit.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
This subchapter regulates toxic air contaminants (TAC) that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained unless a modification is approved by the Director. Since no AOC has been designated anywhere in the state, there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

As described in AQD's "Periodic Testing Standardization," dated December 1, 2011, the following sources are required to show compliance with emission limits by conducting periodic emission testing for the pollutants listed in the following table.

EU ID	Point ID	Pollutant	Emission Limits (TPY)	CEMS?
B-0008	B-0008	CO	174	Yes
B-0009/B-0010	B-0009/B-0010	NO_X	161	Yes
		CO	129	Yes

EU ID	Point ID	Pollutant	Emission Limits (TPY)	CEMS?
No. 4 FCCU	No. 4 FCCU	CO	110	Yes
		PM_{10}	73[(1)] / 110 [(2)]	No
No. 5 FCCU	No. 5 FCCU	NO_X	116	Yes
		CO	206.7	Yes
		SO_2	257	Yes
		PM_{10}	131	No

1. Based on emission limits as required by 40 CFR Part 63, Subpart UUU.
2. Based on emissions limits established by Consent Decree No. H-01-4430.

Currently, B-0008 and B-0009/B-0010 have continuous emission monitor systems (CEMS) for NO_X and CO. The NO_X CEMS for these units are required under 40 CFR Part 60, Subpart Db and the CO CEMS were originally required under 40 CFR Part 63, Subpart DDDDD. The Subpart DDDDD rule language for CO CEMS was vacated on June 8, 2007; however, the applicant maintained operation of the CEMS for these units. The new boiler rule was issued on January 31, 2013, but no longer requires CEMS to be installed and operated on B-0008 and B-0009/B-0010. The current boiler rule requires annual tune-ups in accordance with 40 CFR §60.7540 to "…optimize total emissions of CO… consistent with manufacturer's specifications, and with any NO_X requirement to which the unit may be subject." The tune-up and optimization includes inspection radiant and economizer section for flue gas leakage, burner flame pattern, and measuring CO emissions.

Therefore, no additional testing or continuous emission monitoring requirements for these units for CO are incorporated into the current Title V permit.

The No. 4 FCCU and No. 5 FCCU have CEMS for NO_X and CO as required by 40 CFR Part 63, Subpart UUU. Therefore, separate periodic testing for these pollutants from these emission sources is not required.

Based on the guidelines for periodic testing for criteria pollutants, which is described in AQD's "Periodic Testing Standardization," the periodic testing for PM_{10} from No. 4 FCCU and No. 5 FCCU are required to be conducted every 5 years during the Part 70 term because the PM_{10} emission limits are between 100 TPY and 250 TPY. However, the permittee is already required to do PM_{10} testing for both FCCs every 5 years, per 40 CFR §63.1571(a)(5). Therefore, separate periodic testing for these pollutants from these emission sources is not required. These requirements have been incorporated into the current Title V permit.

The following Oklahoma Air Pollution Control Rules are not applicable to this facility:

OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain, Feed, or Seed Operations	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Landfills	not in source category

SECTION XIII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]

The facility is a major stationary source for NO_X, CO, SO_2, VOC, PM_{10}, and $CO_{2\text{-equivalent}}$. The project in this permit was determined to be subject to PSD review based on project emission increases which exceed the PSD SER for CO emissions. The project emissions increase analysis review is presented in Section VI. The required BACT Analysis and Ambient Air Impacts Analysis are presented in Sections VII and VIII, respectively. Any future increases must be evaluated in the context of PSD significance levels: 40 TPY NO_X, 100 TPY CO, 40 TPY SO_2, 40 TPY VOC, 15 TPY PM_{10}, 10 TPY Total Reduced Sulfur, 0.6 TPY lead, or 75,000 TPY CO_2-equivalent.

NSPS, 40 CFR Part 60 [Subparts A, Db, J, Ja, Kb, GGGa, QQQ, and IIII Are Applicable]

Subpart A, General Provisions. This subpart requires the submittal of notifications for NSPS-affected sources, which for the 2020-2022 LRP Projects are new fugitive sources. Within 30 days after starting construction of the affected sources, the permittee must notify DEQ that construction has commenced. A notification of the actual date of initial startup of any affected source must be submitted within 15 days after such date. Initial performance tests are to be conducted within 60 days of achieving the maximum production rate, but not later than 180 days after initial startup of the source. The permitted must notify DEQ at least 30 days prior to any initial performance test and must submit the results of the initial performance tests to DEQ. The permit will require compliance with the notification requirements in Subpart A. These requirements are incorporated into the permit under EUG-FW for facility-wide applicable requirements.

Subpart A also specifies general control device requirements for control devices used to comply with applicable subparts. Standards for flares used to comply with emissions limitations are stated in 40 CFR §60.18. Subpart GGG requires compliance with 40 CFR §§60.482-10, and 60.482-10 requires compliance with §60.18 for flares used to comply with the standards. 40 CFR §60.18(f)(5) states that the maximum steam-assisted flare exit velocity, V_{max}, shall be determined by the following equation:

$$\text{Log}_{10}(V_{max}) = (H_t + 28.8)/31.7$$

where H_t = the net heating value of the flared gas, MJ/SCM. The section further requires that the flare be monitored for the presence of a pilot flame and that the flare be operated with no visible emissions.

The facility operates flares that are subject to this subpart since they control VOC streams from NSPS Subpart GGGa-affected equipment. Each flare's pilot flame is monitored either by thermocouples or infrared cameras and each flare meets the design criteria specified.

The permittee has calculated that under a worst-case scenario, Flare-Temp would meet the requirements of performance testing under this part. EPA notified Oklahoma Air Quality on September 12, 2000, that the calculations were sufficient to demonstrate that the flare would meet the requirements of this part and granted a waiver of performance testing.

Subpart D, Steam Generating Units. This subpart affects steam generating units with a rated heat input above 250 MMBtu/hr that were constructed after August 17, 1971. The Ponca City Refinery operates steam boilers which meet the applicability criteria. Since these boilers also meet the applicability criteria for Subpart Db, they are subject only to Subpart Db according to 40 CFR §60.41b(j).

The refinery permanently shutdown waste heat boiler B-5004 on June 4, 2020, and replaced it with a shell-and-tube waste heat exchanger. The shell-and-tube waste heat exchanger will not be fuel gas supplemented and not be subject to this subpart.

Subpart Da, Electric Utility Steam Generating Units. This subpart affects electric utility steam generating boilers with a rated heat input greater than 250 MMBtu/hr and that were constructed after September 18, 1978. The refinery does not operate any electric utility steam generating boilers.

Subpart Db, Steam Generating Units. This subpart affects boilers with a rated heat input above 100 MMBtu/hr that commenced construction, reconstruction, or modification after June 19, 1984. The facility operates equipment that is subject to this subpart. The requirements of this subpart are incorporated into the permit under individual EUGs.

Subpart Dc, Small Steam Generating Units. This subpart affects boilers with a rated heat input between 10 and 100 MMBtu/hr that commenced construction, reconstruction, or modification after June 9, 1989. Subpart Dc specifically excludes process heaters. The refinery does not operate boilers meeting the applicability criteria of this subpart.

Subpart J, Petroleum Refineries. This subpart applies to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and Claus sulfur recovery plants. All fluid catalytic cracking unit catalyst regenerators, which commence construction or modification after June 11, 1973, but before January 17, 1984, are subject to the following limitations:

- a PM emission limitation of 1.0 lb/1,000 lbs of coke burn-off, which is required to be continuously monitored and recorded;
- a CO emission limitation of 500 ppm by volume on a dry basis which is required to be continuously monitored and recorded; and
- a SO_X emission limitation of 20 lb/ton coke burn-off

As specified by the Consent Decree No. H-01-4430, the No. 5 FCCU regenerator became subject to the PM limitations of NSPS Subpart J on December 31, 2006. These requirements are incorporated into the permit for the FCCU.

As specified by the Consent Decree No. H-01-4430, the No. 5 FCCU regenerator became subject to the CO emission limitations of NSPS Subpart J on June 30, 2003. These requirements are incorporated into the permit for the FCCU.

On November 23, 2006, a wet gas scrubber (WGS) installed on the No. 5 FCCU began operation. Following startup of the WGS, compliance of the No. 5 FCCU complied with NSPS Subpart J for SO_2 by meeting the requirements of 40 CFR §60.104(b)(1), i.e. "[…] maintain sulfur dioxide emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv) […]". Per 40 CFR §60.106(h)(4), the 50 ppmv SO_2 standard is to be reported on an O_2-free basis. Per 40 CFR §60.106(h)(2), compliance with the standard is demonstrated using an average ppmv SO_2 @ 0% O_2 calculated on a 7-day rolling average basis. Upon startup of the WGS, the No. 5 FCCU became subject to the requirements of NSPS Subpart J for particulate matter (PM). Initial compliance was demonstrated by a stack test conducted on March 15, 2007.

Upon startup of the WGS, the No. 5 FCCU became subject to the requirements of NSPS Subpart J for opacity. The facility submitted a request for approval of an alternative monitoring plan (AMP) to be used to demonstrate compliance with the opacity requirements of NSPS Subpart J in lieu of the requirements of 40 CFR §60.102(a)(2) and 40 CFR §60.105(a)(1). EPA issued a final approval of the AMP on April 5, 2011.

Calculation of coke burn-off is required to demonstrate compliance with the PM requirements of 40 CFR §§60.102(a)(1) and 60.104(b)(2). A request for approval of an Alternative Monitoring Plan for calculating coke burn-off for the No. 5 FCCU was submitted to EPA on February 11, 2005, and was approved by EPA on August 17, 2011. Upon permanent shutdown of waste gas boiler B-5004 on or before December 31, 2022, the No. 5 FCCU coke burn-off will be calculated using the procedures specified in 40 CFR §60.106(b)(3).

Subsequent Refinery MACT II rule changes required that an opacity AMP be approved for compliance with the opacity limit. Re-approval for The No. 5 FCCU opacity AMPs was requested from EPA and granted on January 11, 2018.

All fuel combustion devices which commence construction or modification after June 11, 1973, are subject to a fuel gas H_2S limitation of 0.10 grains/dscf (160 ppmvd at 60°F) which is required to be continuously monitored and recorded. Consent Decree No. H-01-4430 required all of the facility's heaters, boilers, and flares that combust refinery fuel gas to be subject to this subpart, regardless of construction or modification date.

All refinery fuel gas (RFG) combusted by affected heaters and boilers is monitored by H_2S CEMS or by methods specified in agency-approved alternate monitoring plans. These requirements are incorporated into the permit for heaters and boilers.

RFG combusted in refinery flares complies with the continuous monitoring requirement provisions of this subpart.

The No. 4 FCCU Yield Improvements and Reliability project includes modification/reconstruction of the No. 4 FCCU, which is currently subject to and in compliance with the limitations and requirements of this subpart. As a result of the Yield Improvements and Reliability project, the No. 4 FCCU will become subject to NSPS Subpart Ja.

The No. 5 FCCU Waste Heat Boiler Replacement project involved replacement of the No. 5 FCCU waste heat boiler (B-5004) with a shell-and-tube waste heat exchanger. This project will result in an increase in CO emissions from the No. 5 FCCU resulting in a modification under NSPS. As a result of the No. 5 FCCU Waste Heat Boiler Replacement project, the No. 5 FCCU will become subject to NSPS Subpart Ja for emissions of CO.

No other sources that are subject or potentially subject to NSPS Subpart J will be constructed, reconstructed, or modified by the project in this permit.

Subpart Ja, Petroleum Refineries. This subpart affects fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares and sulfur recovery plants which commence construction, reconstruction or modification after May 14, 2007. Subpart Ja also affects flares which commence construction, reconstruction, or modification after June 24, 2008.

The No. 4 FCCU Yield Improvements and Reliability project will result in reconstruction of the No. 4 FCCU. As such, the No. 4 FCCU will be subject to the conditions, requirements, etc., of this subpart.

The No. 5 FCCU Waste Heat Boiler Replacement project will result in modification of the No. 5 FCCU as defined in 40 CFR §60.2. As such, the No. 5 FCCU will be subject to the conditions, requirements, etc., of this subpart related to emissions of CO.

Per the definition of "modification" as it pertains to flares included in 40 CFR §60.100a(c)(1) and (2), the Ponca City Refinery flares have been previously modified. However, prior to being modified, the Ponca City Refinery flares became subject to NSPS Subpart J under federal consent decree CA No. H-01-4430. Per 40 CFR §60.103a(f),

> *[M]odified flares that have accepted applicability of subpart J under a federal consent decree shall comply with the subpart J requirements as specified in the consent decree, but shall comply with the requirements of paragraph (h) of this section and the requirements of §60.107a(a)(2) by no later than November 11, 2015.*

The Ponca City Refinery flares, delayed coking unit, No. 4 FCCU, No. 5 FCCU, and furnaces H-0001, H-5002, H-9301, and H-0060 comply with the relevant requirements, work practices, etc., of Subpart Ja.

Subpart Ja established a fuel gas H_2S limitation for all fuel gas combustion devices, except for flares, which commence construction, reconstruction, or modification after May 14, 2007, of 162 ppmv determined hourly on a 3-hour rolling average basis and 60 ppmv determined daily on a 365 successive calendar day rolling average basis. The provisions of Subpart Ja apply only to flares which commence construction, modification, or reconstruction, after June 24, 2008. Subpart Ja requires the fuel gas H_2S concentration to be continuously monitored and recorded. This subpart also establishes a flare flow limitation of 500,000 standard cubic feet per day (SCFD) above the baseline, based on a 24-hr rolling average, except for process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions.

Subpart K, Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978. This subpart affects storage vessels for petroleum liquids which have a storage capacity greater than 40,000 gallons but less than 65,000 gallons and which commenced construction, reconstruction, or modification after March 8, 1974, or which have a capacity greater than 65,000 gallons which commenced construction, reconstruction, or modification after June 11, 1973, and prior to May 19, 1978. The facility operates tanks that meet these criteria, but 40 CFR Part 63 Subpart CC overlap provisions specify compliance with 40 CFR Part 63 Subpart G instead of NSPS Subpart K standards.

Subpart Ka, Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984. This subpart affects storage vessels for petroleum liquids that have a storage capacity greater than 40,000 gallons and which commenced construction, reconstruction, or modification after May 18, 1978, and prior to July 23, 1984. The facility does not operate any tanks subject to this subpart.

Subpart Kb, Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984, and On or Before October 4, 2023. This subpart affects volatile organic liquids (VOLs) storage vessels (including petroleum liquids storage vessels) for which construction, reconstruction, or modification commenced after July 23, 1984. This subpart does not apply to storage vessels with capacities greater than or equal to 39,890 gallons (151 m^3) storing liquids with a maximum true vapor pressure less than 0.51 psia (3.5 kPa) or with capacities greater than or equal to 19,813 gallons, but less than 39,890 gallons storing liquids with a maximum true vapor pressure less than 2.2 psia (15.0 kPa).

Subpart Kb provides design standards along with monitoring, reporting, and recordkeeping requirements for storage tanks in volatile organic liquid service. In addition, 40 CFR §60.112b specifies that vessels with a design capacity greater than or equal to 39,890 gallons containing a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 0.75 psia, but less than 11.1 psia shall have one of the following vapor control devices: an external fixed roof in combination with an internal floating roof; an external floating roof; a closed vent system to a control device (flare, condenser, or absorber); or an equivalent system.

The facility operates storage vessels subject to this subpart. 40 CFR Part 63 Subpart CC overlap provisions for storage vessels specify compliance with the inspection requirements of 40 CFR Part 60 Subpart Kb except as noted in 40 CFR §63.640(n)(8).

The refinery operates many process tanks within its process units for blending, reactions, surge control, bottoms receivers, or other similar purposes. Generally, these tanks collect discharged raw or intermediate materials from equipment within the process before it is transferred to other equipment within the process. Process tanks are specifically exempt from the definition of storage vessel under Subpart Kb.

Subpart Kc, Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After October 4, 2023. This subpart applies to each storage vessel with a capacity greater than or equal to 20,000 gallons (75.7 m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after October 4, 2023, except as provided in § 60.110c(b). This subpart established requirements for internal floating roof tanks, external floating roof tanks, closed vent systems routed to a control device, fuel gas system, or process, and storage vessel degassing.

The facility operates several storage vessels with a capacity greater than or equal to 20,000 gallons that are used to store volatile organic liquids (VOL) with maximum true vapor pressures of greater than 0.25 psia; however, none of the storage vessels on-site commenced construction, reconstruction, or modification after October 4, 2023. §60.110c(e) states that for the purpose of this subpart, "change in the method of operation of, an existing facility which increases the amount of any air pollutant" in the definition of modification in § 60.2 or "operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies" in § 60.14(a) means a change in operation occurs if the storage vessel is used to store a VOL that has a greater maximum true vapor pressure than all VOL historically stored or permitted; and the exemption in §60.14(e)(4) regarding alternative fuel or raw material does not apply to storage vessels. However, based on §60.110c(e) the potentially applicable existing storage vessels could be modified such that they become subject to the requirements of this subpart by storing a VOL that has a greater maximum true vapor pressure than all VOL historically stored or permitted. Additionally, any new storage vessels with a capacity greater than or equal to 20,000 gallons that are used to store volatile organic liquids (VOL) with maximum true vapor pressures of greater than 0.25 psia would be subject to the requirements of this subpart. Therefore, the requirements of this subpart will be incorporated into the permit.

Subpart GG, Stationary Gas Turbines. There are no stationary gas turbines at this facility.

Subpart VV, Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced after January 5, 1981, And On Or Before November 7, 2006. This subpart affects each valve, pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service and any devices or systems required by this subpart which commenced construction or modification after January 5, 1981, and which is located at a synthetic organic manufacturing facility. The Ponca City Refinery is not a synthetic organic manufacturing facility and is not subject to this regulation.

Subpart VVa, Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced after November 7, 2006. This subpart affects each valve, pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service and any devices or systems required by this subpart which commenced construction or modification after November 7, 2006, and which is located at a synthetic organic manufacturing facility. The Ponca City Refinery is not a synthetic organic manufacturing facility and is not subject to this regulation. However, certain portions of this regulation are referenced for compliance 40 CFR Part 60 Subpart GGGa. See details in the Subpart GGGa regulatory applicability.

Subpart GGG, Equipment Leaks of VOC in Petroleum Refineries For Which Construction, Reconstruction, Or Modification Commenced After January 4, 1983, And On Or Before November 7, 2006. This subpart affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in a process unit and each compressor in VOC service which commenced construction, reconstruction or modification after January 4, 1983, and on or before November 7, 2006, and which is located at a petroleum refinery. This regulation specifies using portions of NSPS Subpart VV. For any affected equipment in >5 wt% organic HAP service, 40 CFR Part 63 Subpart CC requires affected equipment to comply only with the requirements from 40 CFR Part 63 Subpart CC. Subpart CC specifies compliance using requirements from 40 CFR Part 60 Subpart VV. The Ponca City Refinery previously agreed that all existing affected equipment was modified after January 4, 1983, under the provisions of 40 CFR §§60.14 or 60.15, regardless of construction date. The Ponca City Refinery agreed that all existing affected equipment was modified after November 7, 2006, under the provisions of 40 CFR §§60.14 or 60.15, regardless of construction date, and so is now subject to the requirements of NSPS Subpart GGGa.

Subpart GGGa, Equipment Leaks of VOC in Petroleum Refineries For Which Construction, Reconstruction, Or Modification Commenced After November 7, 2006. This subpart affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in a process unit and each compressor in VOC service which commenced construction, reconstruction or modification after November 7, 2006, and which is located at a petroleum refinery. This regulation specifies using portions of NSPS VVa. Among the exemptions included in the regulation, NSPS GGGa states that connectors in gas/vapor or light liquid service are exempt from the standards for connectors in gas/vapor service and in light liquid service included in NSPS VVa, provided the owner or operator complies with standards for pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service included in NSPS VVa for all connectors, not just those in heavy liquid service. For any affected equipment in >5 wt% organic HAP service, the overlap provisions of 40 CFR Part 63 Subpart CC state that equipment leaks that are also subject to the provisions of NSPS GGGa are required to comply only with the provisions specified in NSPS GGGa. The applicable requirements from 40 CFR Part 60 Subpart VVa and 40 CFR Part 60 Subpart GGGa are incorporated into the permit for piping component fugitive leaks. The facility has voluntarily agreed that all existing affected equipment was modified after November 7, 2006, under the provisions of 40 CFR §§60.14 or 60.15, regardless of construction date, and so is now subject to the requirements of NSPS Subpart GGGa. Any new components installed as part of the project in

this permit will be subject to this subpart and will be incorporated into the facility's Leak Detection and Repair (LDAR) program.

Subpart NNN, VOC Emissions from SOCMI Distillation Operations. This subpart applies to each affected facility (distillation units and recovery systems) that is part of a process unit that produces any of the chemicals listed in §60.667 as a product, co-product, by-product, or intermediate. The affected facilities are (1) each distillation unit not discharging its vent stream into a recovery system, (2) each combination of distillation unit and the recovery system into which its vent stream is discharged, or (3) each combination of two or more distillation units and the common recovery system into which their vent streams are discharged. The definition of "vent stream" excludes relief valves and fugitive equipment leaks. The distillation units constructed, reconstructed, or modified after December 30, 1983, currently do not produce NSPS Subpart NNN-listed chemicals that are sold as feed stocks to a SOCMI unit or used within the Ponca City Refinery as feed stocks to SOCMI units.

Subpart OOO, Nonmetallic Mineral Processing Plants. The coke processed at the Coke Handling Facility is not considered a nonmetallic mineral and, therefore, is not subject to this subpart.

Subpart QQQ, VOC Emission from Petroleum Refinery Wastewater Systems. This subpart applies to individual drain systems, oil-water separators, and aggregate facilities located in a petroleum refinery and which commenced construction, modification, or reconstruction after May 4, 1987. Drains are required to be equipped with water seal controls. Junction boxes are required to be equipped with a cover and may have an open vent pipe. Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.

The facility operates sewer components that are subject to this subpart. The overlap provisions for wastewater in 40 CFR Part 63 Subpart CC specify that Group 1 wastewater streams managed in a piece of equipment that is also subject to Subpart QQQ are required only to comply with Subpart CC. Subpart CC specifies compliance in accordance with 40 CFR Part 61 Subpart FF. The applicable requirements from 40 CFR Part 63 Subpart CC, 40 CFR Part 60 Subpart QQQ, and 40 CFR Part 61 Subpart FF are incorporated into the permit under the EUG for process sewer component fugitive leaks.

Storage vessels subject to the standards and associated requirements of NSPS Subparts K, Ka or Kb are not subject to Subpart QQQ. However, for oil-water separators also subject to 40 CFR Part 61 Subpart FF (or subject to 40 CFR Part 63 Subpart CC which requires compliance with Subpart FF), the Subpart FF alternate standards for oil-water separators specify compliance with the alternate standards for oil-water separators in Subpart QQQ, which lists the standards for floating roofs in Subpart Kb along with a few requirements specific to Subpart QQQ. The applicable requirements from 40 CFR Part 63 Subpart CC, 40 CFR Part 61 Subpart FF, and 40 CFR Part 60 Subpart QQQ and Subpart Kb are incorporated into the permit for tanks considered oil-water separators.

Subpart IIII, Stationary Compression Ignition Internal Combustion Engines. This subpart affects stationary compression ignition (CI) internal combustion engines (ICE) based on power and

displacement ratings, depending on date of construction, beginning with those constructed after July 11, 2005. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator. The facility owns and operates emergency CI ICE that are subject to Subpart IIII. The Ponca City Refinery may temporarily rent and operate CI ICE on-site that are subject to Subpart IIII. However, due to the temporary nature of their operation and because they are not owned by the Ponca City Refinery, rental CI ICE providers are responsible for proper operation and maintenance, emission standard compliance demonstrations, initial notifications, and recordkeeping.

Subpart JJJJ, Stationary Spark Ignition (SI) Internal Combustion Engines (ICE). This subpart was proposed on June 12, 2006. For the purposes of this subpart, the date of construction is the date the engine is ordered by the owner or operator. All owners or operators of SI ICE will be required to keep records of all maintenance conducted on an engine per 40 CFR §60.4245(a)(2).

NESHAP, 40 CFR Part 61 [Subparts A, M, and FF are Applicable]
Subpart A, General Provisions. This subpart requires submittal of notifications for NESHAP-affected sources related to commencement of construction, initial startup, and initial performance testing. This subpart also contains general recordkeeping, monitoring and testing requirements. These requirements apply to equipment subject to NESHAP Part 61 regulations, unless otherwise specified by those subparts. These requirements are incorporated into the permit under EUG-FW for facility-wide applicable requirements.

Subpart J, Equipment Leaks of Benzene. This subpart applies to pumps, compressors, pressure relief devices, sampling connections, open-ended lines, valves, or flanges and other connectors, product accumulator vessels, and control devices or systems that are intended to operate in benzene service, which is defined as having more than 10% benzene by weight. The benzene concentration for each affected unit at the facility is less than 10% by weight and is not intended to operate in benzene service. Therefore, Subpart J is not applicable to this facility.

Subpart M, Asbestos. This subpart applies to certain activities involving asbestos. The facility engages in asbestos removal, demolition and disposal and is subject to the applicable standards in this subpart. These requirements are incorporated into the permit under EUG-FW for facility-wide applicable requirements.

Subpart FF, Benzene Waste Operations. This subpart applies to waste streams at chemical manufacturing plants, coke-byproduct recovery plants, and petroleum refineries that have benzene-containing hazardous waste treatment, storage, and disposal facilities. Affected equipment at the facility includes tanks, containers, and individual drain systems. Affected equipment handling waste streams where the benzene content is less than 10 ppmw is exempted. The stormwater collection system is segregated from the process sewer system and, therefore, is not subject to this subpart. The facility operates equipment that is subject to this subpart. The requirements from this subpart are incorporated into the permit under EUGs for process sewer equipment leaks and for tanks handling wastewater.

The project in this permit will not install any new equipment that would otherwise be subject to this subpart. Therefore, the equipment installed as a part of the 2020-2022 LRP Project will not be subject to Subpart FF.

NESHAP, 40 CFR Part 63

[Subparts A, Q, CC, DD, WW, UUU, EEEE, ZZZZ, DDDDD, and GGGGG are Applicable]

Subpart A, General Provisions. This subpart requires submittal of notifications for NESHAP-affected sources related to commencement of construction, initial startup, and initial performance testing. This subpart also includes general provisions for operation and maintenance of affected equipment, startup, shutdown and malfunction plans, monitoring, recordkeeping and reporting. These requirements apply to equipment subject to NESHAP Part 63 regulations, unless otherwise specified by those subparts. These requirements are incorporated into the permit under EUG-FW for facility-wide applicable requirements.

Subpart A also specifies general control device requirements for control devices used to comply with applicable subparts. Standards for flares used to comply with emissions limitations are stated in 40 CFR §63.11. 40 CFR §63.11(b)(7) states that the maximum steam-assisted flare exit velocity, V_{max}, shall be determined by the following equation:

$$\text{Log}_{10}(V_{max}) = (H_t + 28.8)/31.7$$

where H_t = the net heating value of the flared gas, MJ/SCM. §63.11(b) also requires that the flare be monitored for the presence of a pilot flame and that the flare be operated with no visible emissions. The facility operates flares that are subject to this subpart since they control HAP streams from Subpart CC and UUU affected equipment. Each flare's pilot flame is monitored by either by thermocouples or infrared cameras and each flare meets the design criteria specified.

The permittee has calculated that under a worst-case scenario, Flare-Temp would meet the requirements of performance testing under NSPS Subpart A. EPA notified Oklahoma Air Quality on September 12, 2000, that the calculations were sufficient to demonstrate that the flare would meet the requirements of NSPS Subpart A and granted a waiver of performance testing. This waiver can be extended to flare performance testing under this part because the criteria are identical to those specified in NSPS Subpart A.

Subpart Q, Industrial Process Cooling Towers. This subpart applies to all new or existing industrial process cooling towers (IPCTs) that utilize chromium–based water treatment chemicals on or after the rule effective date of September 8, 1994. The facility operates two IPCTs, Y-0002 and Y-0002A, that were operated with chromium-based water treatment chemicals after September 8, 1994. Chromium-based water treatment chemicals were eliminated from use before the compliance date of March 8, 1996. Therefore, the only requirements from this subpart that applied to Y-0002 and Y-0002A were the initial notification and notification of compliance status.

Subpart CC, Petroleum Refineries (Refinery MACT I). This subpart establishes standards for control of HAP from petroleum refineries. Subpart CC affects miscellaneous process vents (except FCCUs and catalyst regenerators), storage vessels, wastewater streams and treatment operations, equipment leaks, gasoline loading racks, marine vessel loading operations, storage vessels and

equipment leaks associated with pipeline breakout stations, heat exchange systems associated with petroleum refinery process units, and releases associated with decoking operations. Of the affected equipment, storage tanks, equipment leaks, process vents, wastewater streams and treatment, a gasoline loading rack, heat exchange systems, and decoking operations are present at this refinery.

Storage tanks: storage tanks at an existing source equal to or larger than 40 m^3 (10,567 gallons) containing any listed HAP are subject. If the tanks are greater than or equal to 177 m^3 (46,758 gallons), have an annual average true vapor pressure of greater than or equal to 8.3 kPa (1.2 psia), a maximum TVP of greater than or equal to 10.4 kPa (1.5 psia), and contain more than 4 wt.% HAP, the tanks are subject to controls. The Ponca City Refinery has chosen to comply with 40 CFR Part 63, Subpart WW as allowed by Subpart CC for storage tanks in EUG TNK-1. Applicable requirements for storage tanks are incorporated into the permit under the EUGs for storage vessels.

This subpart defines, in part, a Group 1 storage vessel as:

> *On an after February 1, 2016:*
>
> *(i) A storage vessel at an existing source that has a design capacity greater than or equal to 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 5.2 kilopascals (0.75 pounds per square inch) and annual average HAP liquid concentration greater than 4 percent by weight total organic HAP;*
>
> *(ii) A storage vessel at an existing source that has a design storage capacity greater than or equal to 76 cubic meters (20,000 gallons) and less than 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 13.1 kilopascals (1.9 pounds per square inch) and annual average HAP liquid concentration greater than 4 percent by weight total organic HAP;*
>
> *(iii) A storage vessel at a new source that has a design storage capacity greater than or equal to 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 3.4 kilopascals (0.5 pounds per square inch) and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP; or*
>
> *(iv) A storage vessel at a new source that has a design storage capacity greater than or equal to 76 cubic meters (20,000 gallons) and less than 151 cubic meters (40,000 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 13.1 kilopascals (1.9 pounds per square inch) and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP.*

The South Tank Farm (STF) crude oil storage tanks currently have individual capacities greater than 177 cubic meters. The tank, tentatively T-617, that will be dedicated to light crude oil storage will have an estimated maximum true vapor pressure, an annual average true vapor pressure, and an annual weight percent total organic HAP greater than the MACT Subpart CC limits for Group 1 storage vessels. As such, tank T-617 will be subject to this subpart as a Group 1 storage vessel.

Process Vents: existing refinery unit process vents with greater than or equal to 20 ppmvd HAP and which emit more than 33 kg/day VOC are subject to control requirements. Subpart CC requires affected vents to be equipped with 98% efficient controls, to be vented to a flare, to be vented to a combustion unit firebox, or to be reduced to 20 ppmvd HAP or less. All Group 1 process vents at this refinery are vented to flares. These requirements are incorporated into the permit under the EUG for Group 1 miscellaneous process vents. The owner or operator may designate vents used only as a result of startup, shutdown, maintenance, or inspection of equipment where equipment is emptied, depressurized, degassed or placed into service as a maintenance vent. The owner or operator does not need to designate a maintenance vent as a Group 1 or Group 2 miscellaneous process vent. However, after removing the liquid and purging the equipment, the maintenance vent can be released if:

1. The vapor in the equipment served by the maintenance vent has a lower explosive limit (LEL) of < 10%, or
2. If there is no ability to measure the LEL of the vapor in the equipment based on the design of the equipment, the pressure in the equipment served by the maintenance vent is reduced to 5 psig, or less. Upon opening the vent, active purging of the equipment cannot be used until the LEL of the vapors in the equipment is < 10%, or
3. The equipment served by the maintenance vent contains < 72 lb of VOC, or
4. If the maintenance vent is associated with equipment containing pyrophoric catalyst (e.g., hydrotreaters and hydrocrackers) and a pure hydrogen supply is not available at the time of the startup, shutdown, maintenance, or inspection activity, the LEL of the vapor in the equipment is < 20%, except for one event per year per piece of equipment, not to exceed by 35%, or
5. If, after applying best practices to isolate and purge equipment served by a maintenance, none of the other applicable criterion can be met prior to installing or removing a blind flange or similar equipment blind, the pressure in the equipment served by the maintenance vent is reduced to 2 psig or less. Active purging of the equipment may be used, provided the equipment pressure at the location where purge gas is introduced remains at 2 psig or less.

The Ponca City Refinery was granted a compliance extension by the Oklahoma Department of Environmental Quality in a letter dated May 31, 2017, to comply with the applicable maintenance vent requirements by October 2, 2018. However, on November 26, 2018, EPA published in the Federal Register technical corrections that would amend the compliance date for maintenance vents during periods of startup, shutdown, maintenance, or inspections to December 26, 2018. This new compliance date superseded the previously approved deadline of October 2, 2018, for compliance with 40 CFR §63.6439(c). These requirements are incorporated into the permit under the EUG for maintenance vents.

Equipment Leaks: these standards affect valves, flanges, pumps, and compressors except for compressors in hydrogen service. Process streams with 5 wt% or more HAP are subject to standards. These requirements are incorporated into the permit under the EUG for piping component fugitive equipment leaks.

Gasoline Loading Terminal: Subpart CC, §63.650 requires compliance with certain standards of 40 CFR Part 63 Subpart R. Subpart R limits total VOC emissions to 10 mg per liter gasoline loaded, requires a leak detection and repair program on meters, arms, and other components which may leak, and requires that tank trucks loaded be vapor-tight. No equipment in the Ponca City Refinery is subject to these requirements.

Wastewater Streams and Treatment: For Group 1 wastewater streams, Subpart CC specifies compliance with the standards, monitoring, recordkeeping, and reporting requirements of 40 CFR Part 61 Subpart FF. These requirements are incorporated into the permit under the EUG for process sewer fugitive equipment leaks and tanks handling wastewater streams.

Heat Exchange Systems: The owner or operator must perform monitoring to identify leaks of total strippable VOC from each heat exchange system subject to the requirements of this subpart. A heat exchange system is exempt if all heat exchangers within the heat exchange system either:

1. Operate with the minimum pressure on the cooling water side at least 35 kilopascals greater than the maximum pressure on the process side; or
2. Employ an intervening cooling fluid containing less than 5% by weight of total organic HAP between the process and the cooling water.

If a leak is detected, the owner or operator must repair the leak to reduce the measured concentration to below the applicable action level as soon as practicable, but no later than 45 days after identifying the leak, except as specified in §§63.654(e) and (f). Applicable requirements have been incorporated into the permit. Cooling tower Y-0009 (located at the wastewater treatment plant) operates as a once through system and the water from the associated clarifier pump is not in PAH service. Therefore, it is not subject to the heat exchange system requirements of this subpart.

Delayed Cokers: Subpart CC, §63.657 limits existing unit decoking operations to a vessel pressure of 2 psig on a rolling 60-event average. Applicable requirements have been incorporated into the permit.

Flare Control Devices: Subpart CC, §63.670 sets forth requirements for flares being used as a control device for an emission point subject to the requirements of Subpart CC. These requirements include operating limitations and monitoring requirements of flares including but not limited to pilot flame presence, visible emissions, flare tip velocity, combustion zone operating limits, and dilution operating limits. Applicable requirements are incorporated into the permit under the EUG FLR-1.

Subpart DD, Off-Site Waste and Recovery Operations. This subpart established standards for control of air emissions from off-site waste that contains listed HAP. The Ponca City Refinery receives less than 1 megagram per year of total HAP from off-site waste and meets the exemption requirements in 40 CFR §63.680(d). Therefore, the facility is exempted from the requirements in §§63.682 through 63.699. The recordkeeping requirements of §63.680(d)(1), (2), and (3) still apply, which require an initial determination of the amount of off-site HAP and whenever it changes enough that to possibly exceed the 1 Mg/year limitation. Documentation must also be kept

demonstrating the calculation for the amount of HAP received. These requirements are incorporated into the permit under as facility-wide applicable requirements.

Subpart WW, Storage Vessels (Tanks) – Control Level 2. The provisions of this subpart apply to the control of emissions from storage vessels for which another subpart references the use of this subpart for such air emissions control. The Ponca City Refinery has chosen to comply with Subpart WW as allowed by 40 CFR Part 63 Subpart CC for storage tanks in EUG TNK-1. Applicable requirements are incorporated into the permit under the EUG TNK-1.

Subpart UUU, Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Plants (Refinery MACT II). This subpart affects the following:

- Process vents or group of process vents on each catalytic cracking unit that is associated with regeneration of the catalyst.
- Process vents or group of process vents on each catalytic reforming unit that is associated with regeneration of the catalyst.
- Process vents or group of process vents that vent from a Claus or other type of sulfur recovery plant unit or the tail gas treatment unit units serving sulfur recovery pants that are associated with sulfur recovery.
- Each bypass line serving a new, existing, or reconstructed catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit.

This subpart does not apply to a gaseous stream routed to a fuel gas system (§63.1562(f)(5)). Fluidized-bed catalytic cracking unit catalyst regenerators are to comply with the requirements of this subpart by no later than April 11, 2005, for control of metal and organic HAP emissions. FCCUs that are in compliance with NSPS Subpart J or NSPS Subpart Ja for PM (§§60.102 or 60.102a(b), respectively) are in compliance with this subpart for metal HAP emissions (§63.1564(a)(1)). FCCUs not subject to NSPS Subpart J for PM can comply with the metal HAP emission requirements of this subpart through one of the four options in paragraphs §§63.1564(a)(1)(i) through (iv). FCCUs that are in compliance with NSPS Subpart J or NSPS Subpart Ja for CO (§§60.103 or 60.103a(b), respectively) are in compliance with this subpart for organic HAP emissions (§63.1565(a)(1)). FCCUs not subject to NSPS Subpart J for CO can comply with the organic HAP emission requirements of this subpart through one of the two options in paragraphs §§63.1565(a)(1)(i) or (ii). Both the No. 4 and No. 5 FCCU are subject to Subpart UUU. The No. 5 FCCU regenerator became subject to NSPS Subpart J for PM on December 31, 2006, under Consent Decree No. H-01-4430.

The No. 2 and No. 3 Catalytic Reforming Units (CRUs) are subject to the emission limits and work practice standards of this subpart. Applicable requirements are incorporated into the permit under the EUG CRU-1.

Subpart EEEE, Organic Liquids Distribution (OLD MACT). This subpart affects storage tanks, transfer racks, equipment leak components, and transport vehicles in organic liquid service that are not covered by another MACT. The definition of organic liquid for applicability to this subpart excludes gasoline, kerosene, and distillate oils and fuel oils, and any liquid with a true vapor pressure less than 0.1 psia. Controls are not required for storage tanks with a capacity of less than

5,000 gallons. The facility is an existing source for the purposes of compliance with this subpart. These requirements are incorporated into the permit under the EUG for tanks subject to Subpart EEEE.

Subpart FFFF, Miscellaneous Organic Chemical Manufacturing (MON MACT). This subpart established requirements for chemical manufacturing process units that meet the criteria specified. The Ponca City Refinery is not subject to this regulation since it is subject to 40 CFR Part 63 Subpart CC.

Subpart YYYY, Stationary Combustion Turbines. This subpart affects new and reconstructed stationary turbines constructed after January 14, 2003. The Ponca City Refinery does not operate any combustion turbines.

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart affects any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions. Owners and operators of the following new or reconstructed RICE must meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines) or 40 CFR Part 60 Subpart JJJJ (for SI engines):

1) Stationary RICE located at an area source;
2) The following Stationary RICE located at a major source of HAP emissions:
   i) Two-stroke, lean-burn (2SLB) and four-stroke, rich-burn (4SRB) stationary RICE with a site rating of ≤ 500 brake HP;
   ii) Four-stroke, lean-burn (4SLB) stationary RICE with a site rating of < 250 brake HP;
   iii) Stationary RICE with a site rating of ≤ 500 brake HP which combust landfill or digester gas equivalent to 10% or more of the gross heat input on an annual basis;
   iv) Emergency or limited use stationary RICE with a site rating of ≤ 500 brake HP; and
   v) CI stationary RICE with a site rating of ≤ 500 brake HP.

No further requirements apply for engines subject to NSPS under this part. Based on emission calculations, this facility is a major source of HAP. This facility operates RICE that are subject to limited parts of the rule. In accordance with §§63.1(b)(3) and 63.10(b)(3) of 40 CFR Part 63 Subpart A, the facility must keep a record of MACT applicability determination for 5 years for engines that do not meet the applicability criteria of this subpart.

Subpart DDDDD, Industrial Boilers and Process Heaters. Subpart DDDDD regulates HAP emissions from industrial boilers and process heaters. All of the facility heaters and boilers are categorized as units "designed to burn gas 1 fuels" per §63.7575 of Subpart DDDDD. Boilers and process heaters in the "units designed to burn gas 1 fuels" subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 or the operating limits in Table 4 of the Subpart DDDDD. One process heater, H-6008, has a heat input capacity greater than 5 MMBtu/hr, but less than 10 MMBtu/hr and so, per §63.7540(a)(11), it must complete a tune-up initially and every 2 years. All of the other facility boilers and process heaters have heat input capacities greater than 10 MMBtu/hr and are not equipped with continuous oxygen trim systems and so, per §63.7540(a)(10), each must complete a tune-up initially and annually. In addition, the facility must complete a one-time energy assessment as per §63.7510(e) and Table 3 of Subpart DDDDD.

Subpart GGGGG, Site Remediation. This subpart established emission limitations and work practice standards from site remediation activities. Site remediation activities can be exempt from this regulation if certain criteria are met. The facility conducts groundwater recovery and remediation of contaminated soils. The groundwater recovery is exempt from compliance with the standards of the regulation because it is being performed under a RCRA Part B Permit #007233836. Removal of spilled materials and contaminated soils, and operation of a soil vapor extraction system are activities subject to the requirements of this rule.

The applicant has determined that it is subject only to the recordkeeping requirements [63.7881(c)] of this subpart because the total quantity of hazardous air pollutant [HAP] contained in remediation material that is excavated, extracted, pumped, or otherwise removed during all site remediation activities at the Ponca City Refinery is less than 1.0 megagram per year. The revision will require the Ponca City Refinery to be subject to all applicable requirements whenever the exemption does not apply.

Subpart PPPPP, Engine Test Cells/Stands. This subpart regulates equipment and activities associated with engine test cells/stands used for testing uninstalled stationary or uninstalled mobile (motive) engines. The preamble to the final rule and the Background Information Document both clarify that test cells that are operated to test or evaluate fuels (such as knock engines), transmissions, electronics, etc., are not part of the source category and are not subject this regulation. The Ponca City Refinery operates knock engines to evaluate fuels and, therefore, is not covered by this regulation.

Compliance Assurance Monitoring (CAM), 40 CFR Part 64 [Not Applicable]
Compliance Assurance Monitoring, as published in the Federal Register on October 22, 1997, applies to any pollutant specific emission unit at a major source that is required to obtain a Title V permit, if it meets all the following criteria:

- It is subject to an emission limit or standard for an applicable regulated air pollutant;
- It uses a control device to achieve compliance with the applicable emission limit or standard; and
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY.

Both of the Ponca City Refinery FCCUs are equipped with a WGS to control emission from the catalyst regenerators. The No. 4 and No. 5 FCCUs at the facility have potential pre-control device emissions that could be greater than major source thresholds. As such, applicability of 40 CFR Part 64 provisions have been evaluated. The following table shows that no pollutant is currently subject to CAM at either of the Ponca City Refinery FCCUs.

No. 4 and No. 5 FCCUs			
Pollutant	**Subject to an emission limitation, other than those exempt under 64.2(b)(1)?**	**Uses a control device to achieve compliance with the applicable emission limit or standard?**	**Pre-control device potential emissions > 100 TPY?**
SO_2	N(1)	Y	Y
CO	N(2)	N	N/A
NO_X	N(1)	N	N/A
PM	N(2)	Y	Y

1. The specific conditions of this Part 70 operating permit specifies use of a CEMS to comply with the SO_2 and NO_X standards at both FCCUs. Pursuant to §64.2(b)(1)(iv), these limits are exempt from CAM because a continuous compliance determination method (CEMS) is part of the Part 70 permit.
2. Both FCCUs are subject to CO and PM emission limitations contained in 40 CFR Part 63, Subpart UUU, which was originally proposed in September 1998. Pursuant to §64.2(b)(1)(i), requirements of CAM do not apply to emission units that are subject to an emission standard proposed after November 15, 1990.

Both the No. 4 and No. 5 FCCUs are equipped with NO_X, CO, and SO_2 CEMS that are installed and operated to meet the requirements of Appendices B and F of 40 CFR Part 60. Additionally, WGS pump discharge pressure, liquid-to-gas ratio, and pressure drop is monitored with continuous parameter monitoring systems in accordance with Table 41 of 40 CFR Part 63, Subpart UUU to ensure compliance with the PM standard. The monitoring systems allow for reporting of all exceedances of the permit limits. Therefore, these units are exempt from the requirements of CAM and no additional requirements are necessary in the permit.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]
Toxic and flammable substances subject to this regulation are present in the facility in quantities greater than the threshold quantities. The most recent revision of the Risk Management Plan was submitted to EPA on November 2, 2015. More information on this federal program is available on the web page: *www.epa.gov/rmp*. These requirements are incorporated into the Standard Conditions of the permit and apply to EUG-FW for facility-wide applicable requirements.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A, B, E, F and H are Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).

Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by

January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.

Subpart B identifies requirements for facilities that maintain, service and repair motor vehicle air conditioner (MVAC) and MVAC-like equipment.

Subpart E specifies container labeling requirements.

Subpart F contains standards and required practices for appliance maintenance, service and repair. It includes standards for equipment used during maintenance, service and repair of appliances and certification requirements for persons performing maintenance, service and repair. Owners and operators of commercial or industrial process refrigeration equipment must comply with leak repair requirements. Owners and operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant added.

The facility maintains, services, and repairs MVAC and MVAC-like equipment subject to Subpart B. The facility owns or operates commercial and industrial process refrigeration equipment including equipment containing more than 50 pounds of refrigerant subject to Subpart F. Facility employees perform maintenance, service, and repairs for commercial and industrial process refrigeration. The facility owns halon-containing equipment that is subject to the provisions of Subpart H. The applicable requirements of this regulation are incorporated into the Standard Conditions of the permit and apply to EUG-FW for facility-wide applicable requirements.

SECTION XIV. COMPLIANCE

The Specific Conditions of this permit contain various testing, monitoring, recordkeeping, and reporting requirements in order to document on-going compliance with emission limits. The specific method used to document compliance was based on the type of emission unit, the type of process equipment, the specific pollutants emitted, and the amount of permitted emissions taking into account other regulatory requirements that an emission unit may be subject to.

On February 14, 2024, a Voluntary Disclosure / Self- Reporting of Noncompliance (DEQ From 100-930) was received from Phillips 66 Company Ponca City Refinery. The Voluntary Disclosure / Self- Reporting of Noncompliance identified an increase in CO emissions from the No. 5 FCCU after replacement of the No. 5 FCCU waste heat boiler with a shell-and-tube waste heat exchanger, which exceeded permitted lb/hr and TPY CO emission limits. The Voluntary Disclosure / Self-Reporting of Noncompliance indicated the Ponca City Refinery had taken numerous corrective measures, including running increased excess oxygen, adding higher amounts of CO promoter, running higher regenerative bed temperatures, running higher air to spent catalyst distributor, running higher dispersion steam, and running higher catalyst bed levels; however, despite these actions, the Ponca City Refinery had been unable to determine the cause of increase CO emissions or to lower the CO emission rate.

This resulted in the opening of Enforcement Case No. 12687 on February 28, 2024. An acknowledgement letter was sent to the Ponca City Refinery on March 5, 2024.

As a follow up to the February 14, 2024, Voluntary Disclosure / Self- Reporting of Noncompliance, the Ponca City Refinery submitted a major source PSD construction permit to address the issue of noncompliance. Additionally, the Ponca City Refinery submitted an addendum to the February 14, 2024, Voluntary Disclosure / Self- Reporting of Noncompliance, received on May 20, 2024, which indicated that with the increase of CO emissions of the No. 5 FCCU, the No. 5 FCCU is now subject to NSPS Subpart Ja for emissions of CO, but the facility had missed several NSPS Subpart Ja notification requirements. The enforcement case is still active and under review.

SECTION XV. TIER CLASSIFICATION AND PUBLIC AND EPA REVIEW

The application has been determined to be **Tier II** based on the request for a PSD major source construction permit. The major source construction permit fee of $5,000 has been received. The applicant requested that the permit be processed through the "Enhanced NSR process" which requires a 30-day public review opportunity and a 45-day EPA review opportunity.

The applicant published a "Notice of Filing a Tier II Application" on July 24, 2024, in *The Ponca City News*, a daily newspaper printed and published in the City of Ponca City, Kay County, Oklahoma, and having general circulation therein. The notice stated that the application was available for public review at the Ponca City Library, 515 E. Grand Ave., Ponca City, OK 74601, or at the Air Quality Division's main office.

The applicant will publish a "Notice of Tier II Draft Permit" as a legal notice in a newspaper of general circulation in the area where the source is located. The "Notice of Tier II Draft Permit" will state that the draft permit will be available for public review at a location in the county where the facility is located, and that the draft permit will also be available for public review at the Air Quality Division main office. The draft permit will be available for a 30-day public review period.

This permit has been approved for concurrent public and EPA review. The draft/proposed permit will be submitted for a 45-day EPA review. If no comments are received from the public the draft/proposed permit will be deemed the proposed permit.

If the Administrator does not object in writing during the 45-day EPA review period, any person that meets the requirements of OAC 252:100-8-8(j) may petition the Administrator within 60 days after the expiration of the Administrator's 45-day review period to make such objection. Any such petition shall be based only on objections to the permit that the petitioner raised with reasonable specificity during the public comment period provided for in 27A O.S. § 2-14-302.A.2., unless the petitioner demonstrates that it was impracticable to raise such objections within such period, or unless the grounds for such objection arose after such period. If the Administrator objects to the permit as a result of a petition filed under OAC 252:100-8-8(j), the DEQ shall not issue the permit until EPA's objection has been resolved, except that a petition for review does not stay the effectiveness of a permit or its requirements if the permit was issued after the end of the 45-day

review period and prior to an EPA objection. If the DEQ has issued a permit prior to receipt of an EPA objection under OAC 252:100-8-8(j), the DEQ will modify, terminate, or revoke such permit, and shall do so consistent with the procedures in 40 CFR §§ 70.7(g)(4) or (5)(i) and (ii) except in unusual circumstances. If the DEQ revokes the permit, it may thereafter issue only a revised permit that satisfies EPA's objection. In any case, the source will not be in violation of the requirement to have submitted a timely and complete application.

This facility is located within 50 miles of the Oklahoma-Kansas border. The State of Kansas and Tribal Nations will be notified of the draft permit.

The applicant has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the property.

The information on all permit actions is available for review by the public in the Air Quality section of the DEQ web page at https://www.deq.ok.gov.

SECTION XVI. SUMMARY

The facility has demonstrated the ability to comply with the requirements of the several air pollution control rules and regulations. Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance or enforcement issues concerning this facility that would prevent the issuance of this permit. Issuance of this construction permit is recommended, contingent upon public, Tribal Nation, and EPA reviews.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Phillips 66 Company **Permit No. 2012-704-C (M-17) PSD**
Ponca City Refinery **Facility ID No. 314**

The permittee is authorized to construct and operate in conformity with the specifications submitted to Air Quality on April 25, 2024, and supplemental information received thereafter. The Evaluation Memorandum dated April 1, 2025, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain limitations or permit requirements. Commencing construction/continuing operations under this permit constitutes acceptance of, and consent to the conditions contained herein:

1. Points of emissions, emission limitations, and standards. [OAC 252:100-8-6(a)]

TANKS

Note: tank capacity, roof type, and construction/modification dates are provided solely for the purposes of documenting regulatory applicability and are not to be construed as operating limitations. The capacities listed represent the physical tank volumes using the internal cross-sectional area and tank shell heights (not taking into consideration safe fill levels).

EUG TNK-1: Storage Vessels Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) and 40 CFR Part 63 Subpart WW

EU ID	Point ID	Physical Capacity (gallon)	Roof Type	Construction / Modification Date	Vapor Pressure Limit (psia) (3)	Throughput Limit (gal/yr) (1)	VOC Limit (TPY) (2)
T-0021E	T-0021E	3,348,342	EFR	1954	<11.1	-	-
T-0101	Permanently removed from service and replaced by tank T-0102 in 2017.						
T-0114	T-0114	439,433	IFR	1919	<11.1	(5)	(5)
T-0148	T-0148	3,377,633	IFR	1923	<11.1	-	-
T-0149	T-0149	3,377,633	IFR	1923	<11.1	-	-
T-0150	T-0150	3,377,633	IFR	1923	<11.1	-	-
T-0151	T-0151	3,377,633	IFR	1923	<11.1	-	-
T-0154	T-0154	6,344,761	EFR	1977	<11.1	-	-
T-0155	T-0155	3,377,633	IFR	1923	<11.1	-	-
T-0158	T-0158	3,351,095	IFR	1924	<11.1	-	-
T-0159	T-0159	3,391,305	IFR	1923	<11.1	-	-
T-0160	T-0160	3,343,857	IFR	1924	<11.1	(5)	(5)
T-0163	T-0163	3,330,990	IFR	1924	<11.1	343,980,000	7.8
T-0164	T-0164	3,351,095	IFR	1924	<11.1	-	(4)
T-0167	T-0167	1,363,316	IFR	1976	<11.1	-	-
T-0170	T-0170	1,078,341	IFR	1920	<11.1	-	-
T-0901	T-0901	3,330,990	IFR	1924	<11.1	252,000,000	-

EU ID	Point ID	Physical Capacity (gallon)	Roof Type	Construction / Modification Date	Vapor Pressure Limit (psia) (3)	Throughput Limit (gal/yr) (1)	VOC Limit (TPY) (2)
T-0902	T-0902	3,357,528	IFR	1971	<11.1	252,000,000	-
T-0953	T-0953	2,339,924	IFR	1944	<11.1	252,000,000	-

1. 12-month rolling total.
2. Calendar year total unless otherwise specified.
3. Maximum calendar month average above which 40 CFR Part 60 Subpart G requires a closed vent system with control device or equivalent control device.
4. T-0102 and T-0164 combined VOC emission limit is 30 TPY.
5. T-0114, T-0156, T-0160, and T-0166 are limited to a combined throughput of 1,450,000,000 gallons per year (12-month rolling total) and a combined VOC limit of 60 TPY (calendar year total).

a. The listed tanks are Group 1 storage vessels and are subject to the control standards of 40 CFR Part 63 Subpart CC. 40 CFR §63.646 specifies that upon a demonstration of compliance with the standards in 40 CFR §63.660 by the compliance dates specified in 40 CFR §63.640(h) (Subpart CC), the standards in §63.646 shall no longer apply. Group 1 storage vessels subject to Subpart CC with floating roofs shall comply with the requirements of 40 CFR Part 63, Subpart WW (§§63.1060 through 63.1067). For these tanks, the permittee shall comply with all applicable requirements of Subpart WW including, but not limited to the following: [40 CFR Part 63 Subpart CC]

   i. The mechanical design and operating specifications for internal floating roof tanks of 40 CFR §63.1063(a)(i).

   ii. The mechanical design and operating specifications for external floating roof tanks of 40 CFR §63.1063(a)(ii).

   iii. The compliance procedures for floating roof tanks of 40 CFR §§63.1063(b) through (e).

   iv. The reporting requirements of 40 CFR §§63.1066 and 63.655(e).

   v. The recordkeeping requirements of 40 CFR §§63.1065 and 63.655(i).

b. For the listed tanks with throughput limits, the permittee shall keep monthly records of the 12-month rolling total throughput for months when the tanks are in VOL service.
[OAC 252:100-43]

c. For the listed tanks with calendar year total VOC emission limits, the permittee shall keep records of annual total VOC emissions when the tanks are in VOL service. Annual VOC emissions shall be determined from VOC emissions correlations based on emission equations from the latest version of AP-42 Section 7.1 or any 3rd party emission calculation software that is based on AP-42 equations for storage tank emissions.
[OAC 252:100-43]

d. The permittee shall operate level switches or other equipment to indicate and notify operations of high level in tanks T-0151, T-0154, T-0158, T-0163, T-0164, T-0170, T-0901, T-0902, and T-0953. This specific condition does not preclude the permittee from future modification or changes in the method of operation of the listed tanks or their associated instrumentation for the purposes of high-level indication and notification so long as a system of indication and notification is operated.

EUG TNK-2: Storage Vessels Subject to 40 CFR Part 60 Subpart Kb and 40 CFR Part 63 Subpart CC (Refinery MACT I)

EU ID	Point ID	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date	Vapor Pressure Limit (psia) (4)	Throughput Limit (gal/yr) (1)	VOC Limit (TPY) (2)
T-0014E	T-0014E	258,678	EFR	1995	<11.1	(3)	(3)
T-0015	T-0015	541,420	EFR	1995	<11.1	(3)	(3)
T-0017E	T-0017E	485,310	EFR	1987	<11.1	-	-
T-0117	T-0117	9,340,615	EFR	1990	<11.1	636,384,000	15.8
T-0119	T-0119	9,340,615	EFR	1990	<11.1	630,000,000	-
T-0121	T-0121	4,694,188	IFR	2005	<11.1	168,000,000	-
T-0141	T-0141	30,455	EFR	1990	<11.1	1,500,000	-
T-0147	T-0147	3,383,872	EFR	1989	<11.1	252,000,000	-
T-0153	T-0153	3,360,000	IFR	2019	<11.1	-	-
T-0156	T-0156	3,826,376	EFR	1993	<11.1	(5)	(5)
T-0162	T-0162	3,310,860	IFR	1924/2011	<11.1	743,505,000	-
T-0165	T-0165	3,405,021	EFR	1991	<11.1	229,950,000	-
T-0166	T-0166	4,060,647	EFR	1991	<11.1	(5)	(5)
T-0176	T-0176	1,355,859	IFR	1988	<11.1	191,625,000	-
T-0177	T-0177	116,512	IFR	1988	<11.1	2,640,000	-
T-0178	T-0178	454,087	IFR	1988	<11.1	191,625,000	-
T-0357	T-0357	8,812	EFR	1993	<11.1	436,800	3.1
T-0402	T-0402	11,844	EFR	1993	<11.1	218,400	3.1
T-0540	T-0540	170,040	IFR	1987	<11.1	-	-
T-0690	T-0690	13,324	EFR	1992	<11.1	840,000	3.1
T-0944	T-0944	1,043,961	IFR	2010	<11.1	262,800,000	-

1. 12-month rolling total.
2. Calendar year total unless otherwise specified.
3. T-0014E and T-0015 are limited to a combined throughput of 4,003,000 gallons per year (12-month rolling total) and a combined VOC limit of 6.6 TPY (calendar year total).
4. Maximum calendar month average above which 40 CFR Part 60 Subpart Kb requires a closed vent system with control device or equivalent control device.
5. T-0114, T-0156, T-0160, and T-0166 are limited to a combined throughput of 1,450,000,000 gallons per year (12-month rolling total) and a combined VOC limit of 60 TPY (calendar year total).

a. Except for T-0141, T-0357, T-0402, and T-0690, the listed tanks are subject to 40 CFR Part 60 Subpart Kb and 40 CFR Part 63 Subpart CC for Group 1 and Group 2 storage vessels. The "overlap" provisions of 40 CFR §63.640(n)(1) state that Group 1 and Group 2 storage vessels are required to comply only with the provisions of Subpart Kb, except as noted in 40 CFR §§63.640(n)(8)(i)-(viii). For these tanks, the permittee shall comply with

all applicable requirements of Subpart Kb and Subpart CC including, but not limited to, the following: [40 CFR Part 60 Subpart Kb and Part 63 Subpart CC]

i. The mechanical design and operating specifications for internal floating roof tanks of 40 CFR §60.112(a)(1).

ii. The mechanical design and operating specifications for external floating roof tanks of 40 CFR §60.112b(a)(2).

iii. The testing and procedures for internal floating roof tanks of 40 CFR §60.113b(a) & 40 CFR §63.640(n)(8).

iv. The testing and procedures for external floating roof tanks of 40 CFR §60.113b(b) & 40 CFR §63.640(n)(8).

v. The reporting and recordkeeping requirements of 40 CFR §60.115b, 40 CFR §63.640(n)(8), and 40 CFR §63.655(e) and (i).

b. T-0141, T-0357, T-0402, T-0690, and T-0944 are subject to 40 CFR Part 61 Subpart FF and 40 CFR Part 63 Subpart CC for wastewater streams. These storage vessels do not store a Group 1 wastewater stream as defined in Subpart CC; therefore, only the general Subpart CC storage vessel recordkeeping provisions apply. For the purpose of compliance with Subpart FF, the vessels are considered tanks. §61.351 of Subpart FF indicates that compliance with Subpart FF can be demonstrated through compliance with Subpart Kb. The facility is complying with the alternate tank standards of Subpart FF by complying with Subpart Kb. The "overlap" provisions of Subpart CC §63.640(n)(8) provide provisions with respect to inspection conditions, delays, and reporting to supersede those of Subpart Kb. For these tanks, the permittee shall comply with all applicable requirements of Subpart Kb and Subpart CC including, but not limited to, the following:
[40 CFR Part 61 Subpart FF and Part 63 Subpart CC]

i. The mechanical design and operating specifications for external floating roof tanks of 40 CFR §60.112b(a)(2).

ii. The testing and procedures for external floating roof tanks of 40 CFR §60.113b(b) and 40 CFR §63.640(n)(8).

iii. The reporting and recordkeeping requirements of 40 CFR §60.115b, 40 CFR §63.640(n)(8), and 40 CFR §63.655(e) & (i).

c. For the listed tanks with throughput limits, the permittee shall keep monthly records of the 12-month rolling total throughput for months when the tanks are in VOL service.
[OAC 252:100-43]

d. For listed tanks with calendar year total VOC emission limits, the permittee shall keep records of annual total VOC emissions when the tanks are in VOL service. Annual VOC

emissions shall be determined from VOC emissions correlations based on emission equations from the latest version of AP-42 Section 7.1 or any 3rd party emission calculation software that is based on AP-42 equations for storage tank emissions.

[OAC 252:100-43]

e. Reserved.

f. While in hydrocarbon service, T-0165, T-0177, and T-0178 must be operated with slotted guidepole controls which meet the following specifications and requirements:

[STERPP Agreement (2/14/01)]

i. The sliding cover shall be in place over the slotted guidepole opening through the floating roof at all times except when the sliding cover must be removed for access. If the control technology includes a float, the float shall be floating within the guidepole at all times except when it must be removed for access to the stored liquid or when the tank is empty.

ii. The permittee shall visually inspect the deck fitting for the slotted guidepole at least once every 10 years and each time the vessel is emptied and degassed. If the slotted guidepole deck fitting or control devices have defects, or if a gap of more than 1/8 inch exists between any gasket required for control of the slotted guidepole deck fitting and any surface that it is intended to seal, such items shall be repaired before filling or refilling the storage vessel with regulated material.

g. The permittee shall operate level switches or other equipment to indicate and notify operations of high level in tanks T-0147, T-0165, T-0176, T-0177, and T-0178. This specific condition does not preclude the permittee from future modification or changes in the method of operation of the listed tanks or their associated instrumentation for the purposes of high-level indication and notification so long as a system of indication and notification is operated.

EUG TNK-3 Storage Vessels Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) Recordkeeping

EU ID	Point ID	Physical Capacity (gallons)	Roof Type	Construction/Mod Date	Vapor Pressure Limit (psia)(3)	Throughput Limit (gal/yr) (1)	VOC Limit (TPY) (2)
D-0924	D-0924	27,900	HFR	2004	-	-	-
T-0003	T-0003	48,661	VFR	Post-1984	<0.5 (4))	-	-
T-0038	T-0038	424,453	EFR	1950	-	-	-
T-0064	T-0064	369,089	VFR	1926	-	-	-
T-0070	T-0070	425,921	VFR	1921	-	-	-
T-0077	T-0077	215,898	VFR	1921	-	-	-
T-0102	T-0102	1,050,000	VFR	2017	-	-	(8)
T-0106E	T-0106E	1,143,749	VFR	1991	<0.5 (4)	-	39.2(1)
T-0107E	T-0107E	1,143,749	VFR	1990	0.5 (4)	291,270,000	20.6
T-0120	T-0120	11,088,636	VFR	1990	-	919,800,000	23.7

EU ID	Point ID	Physical Capacity (gallons)	Roof Type	Construction/Mod Date	Vapor Pressure Limit (psia)[3]	Throughput Limit (gal/yr) [1]	VOC Limit (TPY) [2]
T-0123	T-0123	3,684,661	VFR	1992	-	[5]	[5]
T-0124	T-0124	3,684,661	VFR	1992	-	[5]	[5]
T-0125	T-0125	3,684,661	VFR	1992	-	[5]	[5]
T-0126	T-0126	3,684,661	VFR	1992	-	[5]	[5]
T-0128	T-0128	3,619,157	VFR	1992	-	[5]	[5]
T-0129	T-0129	3,619,157	VFR	1992	-	[5]	[5]
T-0130	T-0130	6,831,266	VFR	1992	-	[5]	[5]
T-0131	T-0131	6,831,266	VFR	1992	-	[5]	[5]
T-0135	T-0135	4,586,000	VFR	1992	-	[5]	[5]
T-0136	T-0136	4,586,000	VFR	1992	-	[5]	[5]
T-0142	T-0142	3,398,254	VFR	1989	<0.5 [4]	-	-
T-0143	T-0143	6,644,304	VFR	1990	-	306,600,000	13.1
T-0144	T-0144	6,644,304	VFR	1991	<0.5 [4]	-	37.1[1]
T-0152	T-0152	3,377,640	EFR	1974/2011	< 0.5 [4]	-	-
T-0161	T-0161	3,363,962	VFR	1974	<1.5 [4]	-	-
T-0168	T-0168	424,453	VFR	1950	-	-	-
T-0169	T-0169	424,453	VFR	1950	-	-	-
T-0171	T-0171	20,000	VFR	1943	-	-	-
T-0179	T-0179	46,998	VFR	1988	<0.5 [4]	40,000,000	-
T-0253	T-0253	31,724	VFR	1994	2.2 [4]	26,280,000	-
T-0254	T-0254	13,535	VFR	1994	-	26,280,000[7]	-
T-0509	T-0509	43,453	VFR	1968	-		-
T-0260	T-0260	26,437	VFR	1987	<0.5 [4]	-	-
T-0500	T-0500	2,819,894	VFR	1983	<1.5 [4]	-	-
T-0501	T-0501	241,140	OT	1990/2019	<0.5 [4]	-	-
T-0536	T-0536	16,919	VFR	1983	-	-	-
T-0561	T-0561	24,418	VFR	1971	-	-	-
T-0633	T-0633	3,383,872	VFR	1985	<0.5 [4]	-	-
T-0636	T-0636	3,349,806	VFR	1929	-	-	-
T-0639	T-0639	2,285,600	VFR	1926/2011	-	-	-
T-0904	T-0904	3,317,318	VFR	1924	-	-	-
T-0905	T-0905	3,317,318	VFR	1924/2009	-	-	-
T-0906	T-0906	1,047,993	VFR	1944	-	-	-
T-0913	T-0913	1,050,262	VFR	1943	-	-	-
T-0914	T-0914	1,054,295	VFR	1943	-	-	-
T-0916	T-0916	66,091	VFR	1944	-	-	-
T-0970	T-0970	1,903,428	VFR	2000	<0.5 [4]	-	-
T-0971	T-0971	1,903,428	VFR	2000	<0.5 [4]	-	-
T-0972	T-0972	1,903,428	VFR	2000	<0.5 [4]	-	-

1. 12-month rolling total.
2. Calendar year total unless otherwise specified.
3. In addition to the indicated values, vapor pressure is also limited to <1.5 psia (maximum) and <1.2 psia (annual average) only if the annual average HAP content is >4 wt% under 40 CFR Part 63 Subpart CC. If annual average HAP content is ≤4wt%, vapor pressure is not limited under Subpart CC.
4. Maximum calendar month average above which 40 CFR Part 60 Subparts K, Ka, or Kb applies.

5. Combined throughput limit for T-0123, T-0124, T-0125, T-0126, T-0128, T-0129, T-0130, T-0131, T-0135, T-0136, and T-0173 is 5,631,000,000 gallons per year (12-month rolling total) and the combined VOC limit is 155 TPY (calendar year total).
6. Reserved.
7. Combined throughput limit for T-0254 and T-0509 is 26,280,000 gallons per year (12-month rolling total).
8. T-0102 and T-0164 combined VOC emission limit is 30 TPY.

a. The listed tanks are Group 2 storage vessels subject to 40 CFR Part 63 Subpart CC but must only comply with recordkeeping requirements. The permittee shall maintain records of dimension, analysis showing capacity, and group determination for the life of the storage tanks. [40 CFR §63.655(i)]

b. For the listed tanks with throughput limits, the permittee shall keep monthly records of the 12-month rolling total throughput for months when the tanks are in VOL service. [OAC 252:100-43]

c. For the listed tanks with calendar year total VOC emission limits, the permittee shall keep records of annual total VOC emissions when the tanks are in VOL service. Annual VOC emissions shall be determined from VOC emissions correlations based on emission equations from the latest version of AP-42 Section 7.1 or any 3rd party emission calculation software that is based on AP-42 equations for storage tank emissions. [OAC 252:100-43]

d. Reserved.

e. The permittee shall operate level switches or other equipment to indicate and notify operations of high level in tanks T-0038 and T-0636. This specific condition does not preclude the permittee from future modification or changes in the method of operation of the listed tanks or their associated instrumentation for the purposes of high-level indication and notification so long as a system of indication and notification is operated.

f. The permittee shall operate the HF Alkylation unit spent potassium hydroxide (KOH) handling and regeneration systems in such a way as to minimize acid soluble oil (ASO) carry-over to the neutralization pit. This specific condition does not preclude the permittee from future modification or changes in the method of operation of the KOH handling and/or regeneration systems so long as any carry-over continues to be minimized.

EUG TNK-4: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 1 Wastewater Streams Handled by Either Tanks or Storage Vessels

EU ID (3)	Point ID	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date	Vapor Pressure Limit (psia) (4)	Throughput Limit (gal/yr) (1)	VOC Limit (TPY) (2)
D-0777	D-0777	564	HFR	Pre-1991	-	-	-
D-0779	D-0779	10,403	HFR	Pre-1991	-	-	-
D-5292	D-5292	1,900	HFR	1943	-	-	-

EU ID [3]	Point ID	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date	Vapor Pressure Limit (psia) [4]	Throughput Limit (gal/yr) [1]	VOC Limit (TPY) [2]
T-0037	T-0037	586,200	EFR	1993	<11.1	1,522,500,000	17.8
T-0201	T-0201	490,573	EFR	1991	<11.1	-	21.6 [1]
T-0202	T-0202	490,573	EFR	1991	<11.1	-	22.2 [1]
T-0203	T-0203	21,995	IFR	1991	<11.1	-	2.0 [1]
T-0204	T-0204	490,573	EFR	1991	<11.1	-	21.5 [1]
T-0205	T-0205	490,573	EFR	1991	<11.1	-	21.5 [1]
T-0551	T-0551	490,573	EFR	1991	<11.1	4,734,000	-
T-0552	T-0552	490,573	EFR	1992	<11.1	4,986,000	-
T-0553	T-0553	256,651	EFR	1991	<11.1	2,542,000[5]	-
T-0554	T-0554	256,651	EFR	1992	<11.1		-
T-0555	T-0555	21,995	IFR	1993	<11.1	691,000	-
T-0651	T-0651	3,363,962	VFR	1923	-	-	-
T-0652	T-0652	3,377,423	VFR	1923	-	-	-
T-0654	T-0654	3,077,933	EFR	1923	-	-	27.4 [1]
T-0665	T-0665	3,752,617	EFR	1991	<11.1	-	26.6 [1]
T-0667	T-0667	21,995	IFR	1991	-	3,600,000	-
T-0669	T-0669	270,401	EFR	1991	<11.1	2,129,000	-
T-0701	T-0701	256,651	EFR	1991	<11.1	-	20.8 [1]
T-0702	T-0702	256,651	EFR	1991	<11.1	-	20.8 [1]
T-0703	T-0703	22,068	IFR	1991	<11.1	-	3.8 [1]
T-0704	T-0704	270,401	EFR	1991	<11.1	-	20.8 [1]
T-0705	T-0705	270,401	EFR	1991	<11.1	-	20.8 [1]
T-0706	T-0706	270,401	EFR	1991	<11.1	26,280,000	-
T-0907	T-0907	1,056,563	IFR	1943	-	-	-
T-0908	T-0908	1,052,278	IFR	1943	-	12,600,000	3.3
T-0910	T-0910	663,215	IFR	1943	-	6,300,000	4.0

1. 12-month rolling total.
2. Calendar year total unless otherwise specified.
3. T-0037, T-0201, T-0202, T-0203, T-0204, T-0205, T-0551, T-0552, T-0553, T-0554, T-0555, T-0665, T-0669, T-0701, T-0702, T-0703, T-0704, T-0705, and T-0706 are considered tanks for the purposes of 40 CFR Part 61 Subpart FF compliance and storage vessels for the purposes of 40 CFR Part 60 Subpart QQQ compliance. T-0654, T-0667, T-0907, T-0908, and T-0910 are considered tanks for the purposes of compliance with Subpart FF but are not subject to Subpart QQQ. D-0777, D0779, D-5292, T-0651, and T-0652 handle wastewater streams and are subject to Subpart FF.
4. Maximum calendar month average above which 40 CFR Part 60 Subpart Kb requires a closed vent system with control device or equivalent control device.
5. Combined throughput limit for T-0553 and T-0554 is 2,542,000 gallons per year (12-month total).

a. All the listed IFR and EFR tanks, except T-0910, T0654, and T-0667 are subject to 40 CFR Part 60 Subpart Kb and Subpart QQQ, 40 CFR Part 61 Subpart FF, and 40 CFR Part 63 Subpart CC. For the purpose of compliance with Subpart FF, they are considered tanks. For the purpose of compliance with Subpart QQQ, they are considered storage vessels. The "overlap" provisions of Subpart CC §63.640(o)(1) state that a Group 1 wastewater stream managed in a piece of equipment that is also subject to the provisions of Subpart QQQ is required to comply only with Subpart CC. Subpart CC §63.647(a) states that equipment

handling a Group 1 wastewater stream shall comply with the requirements of §§61.340 through 61.355 of Subpart FF. §61.351 of Subpart FF indicates that compliance with Subpart FF can be demonstrated through compliance with Subpart Kb. The facility is complying with the alternative tank standards of Subpart FF by complying with Subpart Kb. The "overlap" provisions of Subpart CC §63.640(n)(8) provide provisions with respect to inspection conditions, delays, and reporting to supersede those of Subpart Kb. For these tanks, the permittee shall comply with all applicable requirements of Subpart Kb and Subpart CC, including, but not limited to, the following:[40 CFR Part 60 Subpart QQQ, Part 61 Subpart FF, and Part 63 Subpart CC]

i. The mechanical design and operating specifications for internal floating roof tanks of 40 CFR §60.112b(a)(1).

ii. The mechanical design and operating specifications for external floating roof tanks of 40 CFR §60.112b(a)(2).

iii. The testing and procedures for internal floating roof tanks of 40 CFR §60.113b(a) and 40 CFR §63.640(n)(8).

iv. The testing and procedures for external floating roof tanks of 40 CFR §60.113b(b) and 40 CFR §63.640(n)(8).

v. The reporting and recordkeeping requirements of 40 CFR §60.115b and 40 CFR §63.640(n)(8).

b. Tanks T-0654, T-0667, T-0907, T-0908, and T-0910, are subject to 40 CFR Part 61 Subpart FF, 40 CFR Part 63 Subpart CC, but not Subpart QQQ. For the purpose of compliance with Subpart FF they are considered tanks. Subpart CC §63.647(a) states that equipment handling a Group 1 wastewater stream shall comply with the requirements of §§61.340 through 61.355 of Subpart FF. §61.351 of Subpart FF indicates that compliance with Subpart FF can be demonstrated through compliance with Subpart Kb. The facility is complying with the alternative tank standards of Subpart FF by complying with Subpart Kb. The "overlap" provisions of Subpart CC §63.640(n)(8) provide provisions with respect to inspection conditions, delays, and reporting to supersede those of Subpart Kb. For these tanks, the permittee shall comply with all applicable requirements of Subpart Kb and Subpart CC including, but not limited to, the following:

[40 CFR Part 61 Subpart FF, and Part 63 Subpart CC]

i. The mechanical design and operating specifications for internal floating roof tanks of 40 CFR §60.112b(a)(1).

ii. The mechanical design and operating specifications for external floating roof tanks of 40 CFR §60.112b(a)(2).

iii. The testing and procedures for internal floating roof tanks of 40 CFR §60.113b(a) and 40 CFR §63.640(n)(8).

iv. The testing and procedures for external floating roof tanks of 40 CFR §60.113b(b) and 40 CFR §63.640(n)(8).

v. The reporting and recordkeeping requirements of 40 CFR §60.115b and 40 CFR §63.640(n)(8).

c. Reserved.

d. The listed HFR and VFR tanks are subject to 40 CFR Part 61 Subpart FF and 40 CFR Part 63 Subpart CC for wastewater streams. Subpart CC §63.647(a) states that equipment handling a Group 1 wastewater stream shall comply with the requirements of §§61.340 through 61.355 of Subpart FF. When storing a Group 1 wastewater stream, these tanks shall be operated as a closed-vent system with carbon adsorption system and the permittee shall comply with all applicable requirements of Subpart FF including, but not limited to, the following: [40 CFR Part 61 Subpart FF and 40 CFR Part 63 Subpart CC]

i. The mechanical design and operating specifications of 40 CFR §61.343(a)(1).

ii. The standards for closed-vent systems and control devices of 40 §CFR 61.349.

iii. The standards for delay of repair of 40 CFR §61.351.

iv. The requirements for monitoring of operations of 40 CFR §61.354.

v. The reporting and recordkeeping requirements of 40 CFR §§61.356 and 61.357.

e. For the listed tanks with throughput limits, the permittee shall keep monthly records of the 12-month rolling total throughput for months when the tanks are in VOL service. [OAC 252:100-43]

f. For the listed tanks with 12-month rolling total VOC emission limits, monthly records of 12-month rolling total VOC emissions and the information used to calculate those emissions shall be maintained when the tanks are in VOL service. The following information and methods shall be used to determine monthly emissions:

i. Monthly total throughput records.

ii. Monthly average true vapor pressure records.

iii. VOC emissions correlations based on emission equations from the latest version of AP-42 Section 7.1 or any 3rd party emission calculation software that is based on AP-42 equations for storage tank emissions. [OAC 252:100-43]

g. For listed tanks with calendar year total VOC emission limits, the permittee shall keep records of annual total VOC emissions when the tanks are in VOL service. Annual VOC

emissions shall be determined from VOC emissions correlations based on emission equations from the latest version of AP-42 Section 7.1 or any 3rd party emission calculation software that is based on AP-42 equations for storage tank emissions. [OAC 252:100-43]

h. The permittee shall operate level switches or other equipment to indicate and notify operations of high level in tank T-0652. This specific condition does not preclude the permittee from future modification or changes in the method of operation of the listed tank or its associated instrumentation for the purposes of high-level indication and notification so long as a system of indication and notification is operated.

EUG TNK-5: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 2 Wastewater Streams Handled by Storage Tanks

EU ID	Point ID	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date	Vapor Pressure Limit (psia)	Throughput Limit (gal/yr) (1)	VOC Limit (TPY) (2)
D-0232	D-0232	924	HFR	1989	-	-	-
D-0775	D-0775	10,300	HFR	1990	-	-	-
D-0776	D-0776	10,300	HFR	1990	-	-	-
D-0780	D-0780	10,403	HFR	1990	-	-	-
D-0783	D-0783	3,475	HFR	1990	-	-	-
D-0786-1	D-0786-1	564	HFR	Est. 1990	-	-	-
D-6801	D-6801	5,000	VFR	1964	-	-	-
D-6812	D-6812	16,044	HFR	1991	-	-	-
T-0080	T-0080	105,000	VFR	1941	-	-	-
T-0140	T-0140	4,053	VFR	1990	-	-	-
T-0173	T-0173	5,558	VFR	1992	0.039 (4)	(3)	(3)
T-0648	T-0648	4,576	VFR	1992	-	-	-
T-0680	T-0680	250,000	OT	1993	-	-	-
T-0966	T-0966	14,161	VFR	1945	-	-	-
T-0973	T-0973	213,523	VFR	1960	-	-	-

1. 12-month rolling total.
2. Calendar year total unless otherwise specified.
3. Combined throughput limit for T-0123, T-0124, T-0125, T-0126, T-0128, T-0129, T-0130, T-0131, T-0135, T-0136, and T-0173 is 5,631,000,000 gallons per year (12-month rolling total) and the combined VOC limit is 155 TPY (calendar year total).
4. Annual average.

a. These tanks are not subject to any NSPS or NESHAP standards.

b. For the listed tanks with throughput limits, the permittee shall keep monthly records of the 12-month rolling average throughput for months when the tanks are in VOL service. [OAC 252:100-43]

c. For listed tanks with calendar year total VOC emission limits, the permittee shall keep records of annual total VOC emissions when the tanks are in VOL service. Annual VOC emissions shall be determined from VOC emissions correlations based on emission

equations from the latest version of AP-42 Section 7.1 or any 3rd party emission calculation software that is based on AP-42 equations for storage tank emissions.

[OAC 252:100-43]

d. The permittee shall maintain records of annual average vapor pressure for materials stored in T-0173. [OAC 252:100-43]

EUG TNK-6: 40 CFR Part 63 Subpart EEEE (OLD MACT) Fixed Roof Storage Tanks

EU ID	Point ID	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date	Vapor Pressure Limit (psia)	Throughput Limit (gal/yr)	VOC Limit (TPY)
T-0017	T-0017	350	VFR	1994	-	-	-
T-0018	T-0018	550	VFR	1994	-	-	-
T-0027	T-0027	550	VFR	2006	-	-	-
T-0057	T-0057	550	VFR	2005	-	-	-
T-0058	T-0058	550	VFR	2005	-	-	-
T-0104	T-0104	1,680	VFR	1922	-	-	-
T-0212 E	T-0212E	564	VFR	1971	-	-	-
T-0230	T-0230	4,230	VFR	Pre 2004	-	-	-
T-0527	T-0527	550	VFR	2006	-	-	-
T-0528	T-0528	550	VFR	2007	-	-	-
T-0529	T-0529	550	VFR	2007	-	-	-
T-0542	T-0542	550	VFR	Pre 2000	-	-	-
T-0111	T-0111	550	VFR	2007	-	-	-
T-0511	T-0511	550	VFR	2010	-	-	-
T-0538	T-0538	550	VFR	2011	-	-	-
T-0540 TOTE	T-0540 TOTE	550	VFR	2010	-	-	-
T-0543	T-0543	550	VFR	2010	-	-	-
T-2254	T-2254	550	VFR	2011	-	-	-
T-5005	T-5005	550	VFR	2011	-	-	-
T-9403	T-9403	550	VFR	2012	-	-	-
NP Methanol Tote	NP Methanol Tote	350	VFR	2010	-	-	-
TNK-Misc. Vendor Totes / Tanks	TNK-Misc. Vendor Totes / Tanks	< 5,000	VFR	Any	-	-	-

a. The listed tanks are subject to 40 CFR Part 63 Subpart EEEE. For these tanks, the permittee shall comply with all applicable requirements of Subpart EEEE for existing storage tanks including, but not limited to, the following: [40 CFR Part 63 Subpart EEEE]

i. §63.2382 What notifications must I submit and when and what information should be submitted?

ii. §63.2386 What reports must I submit and when and what information is to be submitted in each?

iii. §63.2390 What records must I keep?

iv. §63.2394 In what form and how long must I keep my records?

b. The permittee shall maintain records to demonstrate that the listed storage tanks with a capacity of 5,000 gallons or more have a true vapor pressure of less than 4.0 psia, annual average. [40 CFR §63.2346]

EUG TNK-7: Storage Tanks Subject to Oklahoma Rules or Permit Requirements

EU ID	Point ID	Physical Capacity (gallons)	Roof Type	Construction/ Modification Date	Vapor Pressure Limit	Throughput Limit (bbl/yr) (1)	VOC Limit TPY (2)
T-0024	T-0024	2,016	VFR	1986	-	-	-
TNK-MP Gasoline	TNK-MP Gasoline	1,000	VFR	2002	-	-	-
TNK-GFMHL #1	TNK-GFMHL #1	500	HFR	2017	-	-	-
TNK-GFMRW #1	TNK-GFMRW #1	500	HFR	2000	-	-	-
TNK-GFMNT1	TNK-GFMNT 1	18,411	IFR	1993	-	-	-

1. 12-month rolling total.
2. Calendar year total unless otherwise specified.

a. Reserved.

b. For the listed tanks with calendar year total VOC emission limits, the permittee shall keep records of annual total VOC emissions when the tanks are in VOL service. Annual VOC emissions shall be determined from VOC emissions correlations based on emission equations from the latest version of AP-42 Section 7.1 or any 3rd party emission calculation software that is based on AP-42 equations for storage tank emissions. [OAC 252:100-43]

EUG TNK-8: Insignificant Activity Storage Tanks

There are no emissions limitations for these tanks.

EU ID	Point ID	Normal Contents	Insignificant Activity Reason
T-0008	T-0008	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0006 E	T-0006 E	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0012	T-0012	Jet Water Pump Surge, Fines Filtering	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0014	T-0014	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0023	T-0023	Diesel Storage at Fuel Pump	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0031	T-0031	Spent Naphthenic Caustic	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0157	T-0157	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0534	T-0534	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0535	T-0535	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0603	T-0603	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
T-0604	T-0604	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
TNK-Fire Training #1	TNK-Fire Training #1	Kerosene storage at Fire Training Grounds	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
TNK-GFMHL #2	TNK-GFMHL #2	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
TNK-GFMST	TNK-GFMST	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
TNK-Misc. Vendor Totes / Tanks	TNK-Misc. Vendor Totes / Tanks	Vendor chemicals with TVP < 1.0 psia and containing < 4% RM1 HAPs, < 5% OLD MACT HAPs, or inorganic	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
TNK-MP Diesel	TNK-MP Diesel	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
TNK-GFMRW #2	TNK-GFMRW #2	Diesel fuel	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia
TNK-Misc. Lube Oil Reservoirs	TNK-Misc. Lube Oil Reservoirs	Lube Oil	App. I: Storage Tanks/Distribution - < 40,000 gal / < 1.5 psia

HEATERS AND BOILERS

EUG HTR-1: 40 CFR Part 60 Subparts J, Db, & Dc and 40 CFR Part 63 Subpart DDDDD Boilers

EU ID	Point ID	Const/ Mod Date	Fired Duty Limit (1) (MMBtu/hr)	Pollutant	Emission Rate Limit (1) (lb/MMBtu)	Emission Limit (1)	
						lb/hr	TPY
B-0008	B-0008	2003 (SC 33)	483	NO_X	0.035 0.20(3)	16.9 -	74.0 -
				CO	--	39.8	174.0
				SO_2	--	15.0	65.6
				VOC	--	2.6	11.4
				PM_{10}	--	3.6	15.9
B-0009/0010	B-0009/0010	2005 (SC 33)	734 (2)	NO_X	0.050 0.20(3)	36.6 -	161.0 -
				CO	--	29.4	129.0
				SO_2	--	22.8	99.7
				VOC	--	4.0	17.4
				PM_{10}	--	5.5	24.2
B-0021	Permanently removed from service by June 2012 and shall not be returned to service.						
B-0022	B-0022	2009 (SC 33)	95(2)	NO_X	0.036 0.20(3)	3.42 -	15.0 -
				CO	0.04	3.80	16.6
				SO_2	--	0.05	0.2
				VOC	--	0.51	2.2
				PM_{10}	--	0.71	3.1

1. 365-day rolling average unless specified otherwise. Time period basis is midnight to midnight (does not include lb/MMBTU limit under NSPS Subparts J and Dc, 40 CFR Part 63, Subpart DDDDD, or OAC 252:100-33).
2. Fired duty is shown for the purposes of regulatory applicability only and is not a permit limit.
3. Based on 3-hour average (from 3 contiguous 1-hour periods) calculated each clock hour.

a. Boilers B-0008 and B-0009/0010 are subject to 40 CFR Part 60 Subpart Db. The permittee shall comply with all applicable requirements including, but not limited to, the following: [40 CFR Part 60 Subpart Db]

i. §60.44b Standards for nitrogen oxides. The boilers are limited to NO_X emissions of 0.20 lb/MMBtu, 30-day rolling average.

ii. §60.46b Performance test and compliance provisions. An annual performance evaluation of the NO_X CEMS must be conducted in accordance with the Methods specified in 40 CFR Part 60 Appendix B.

iii. §60.48b Monitoring of emissions. A continuous monitoring system shall be operated and maintained to record NO_X emissions.

iv. §60.49b Reporting and recordkeeping requirements.

b. The boilers are subject to 40 CFR Part 60 Subpart J. The permittee shall comply with all applicable requirements including, but not limited to, the following:
[40 CFR Part 60 Subpart J]

i. §60.104 Standards for sulfur oxides. Boilers B-0008 and B-0009/0010 shall combust only pipeline grade natural gas, PSA off-gas, or refinery fuel gas with a 3-hour rolling average maximum H_2S concentration of 0.1 gr/dscf (160 ppmv @ 60°F). Boiler B-0022 shall combust only pipeline grade natural gas.

ii. §60.105 Monitoring of emissions and operations. A continuous monitoring system shall be operated and maintained to record either the H_2S content of the fuel gas or the SO_2 concentration in the flue gas. If an SO_2 monitor is used, the SO_2 concentration standard is 20 ppmvd @ 0% O_2, 3-hr rolling average and an oxygen monitor shall also be included for correcting the data for excess air. Boiler B-0022 shall combust only pipeline grade natural gas.

iii. §60.106 Test methods and procedures.

iv. §60.107 Reporting and recordkeeping requirements.

v. §60.108 Performance test and compliance provisions.

c. Compliance with the firing rate limit for boiler B-0008 shall be based on 365-day rolling averages, with each day calculated based on the daily fuel gas usage and weekly heating value, and shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula: [OAC 252:100-43]

$$MMBtu/hr = \frac{1}{365}\sum_{n=1}^{365}\left((MMSCFD)_n(Btu/Scf\ (HHV))_n\left(\frac{1\ day}{24\ hours}\right)\right)$$

where MMSCFD = Daily fuel gas usage;
Btu/Scf (HHV) =Gas heating value (high heat value), determined weekly; and
n = Each day.

d. Compliance with the emissions limits for PM and VOC is demonstrated by the use of good combustion practices. [OAC 252:100-43]

e. Compliance of boilers B-0008 and B-0009/0010 with the SO_2 lb/hr and TPY emission limits shall be based on 365-day rolling averages and 365-day rolling totals, respectively, with each day calculated based on the daily fuel gas usage and H_2S content, and shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formulas: [OAC 252:100-43]

$$\frac{lb}{hr} = \frac{1}{365}\sum_{n=1}^{365}\left((MMSCFD)_n(ppmvd\ H_2S)_n\left(\frac{64\ lb\ SO_2}{lb-mol}\right)\left(\frac{1\ day}{24\ hours}\right)\left(\frac{1\ lb-mol}{379.4\ Scf}\right)\right)$$

$$TPY = \sum_{n=1}^{365}\left((MMSCFD)_n(ppmvd\ H_2S)_n\left(\frac{64\ lb\ SO_2}{lb-mol}\right)\left(\frac{1\ ton}{2{,}000\ lb}\right)\left(\frac{1\ lb-mol}{379.4\ Scf}\right)\right)$$

where MMSCFD = Daily fuel gas usage;
ppmvd H_2S = Daily average hydrogen sulfide concentration (dry, volume basis); and
n = Each day.

f. Compliance with the NO_X and CO lb/hr and TPY emission limits shall be based on 365-day rolling averages and 365-day rolling totals, respectively, with each day calculated based on heater specific (stack test) emission factors and the daily fuel gas usage and weekly heating value, CEMS when available, or the most current version of AP-42 emission factors from Table 1.4-1. Compliance shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formulas:
[OAC 252:100-43]

$$\frac{lb}{hr} = \frac{1}{365}\sum_{n=1}^{365}\left((MMSCFD)_n(Btu/Scf\ (HHV))_n(EF)\left(\frac{1\ day}{24\ hours}\right)\right)$$

$$TPY = \sum_{n=1}^{365}\left((MMSCFD)(Btu/Scf\ (HHV))(EF)\left(\frac{1\ ton}{2{,}000\ lb}\right)\right)$$

where EF = Emission factor, lb/MMBtu;
MMSCFD = Daily fuel gas usage;
Btu/Scf (HHV) = Gas heating value (high heat value), determined weekly; and
n = Each day.

g. Compliance of boilers B-0008 and B-0009/0010 with the NO_X lb/MMBtu emission limit shall be based on 365-day rolling averages, with each day calculated using the daily average CEMS data for the NO_X concentration in the flue gas. Compliance shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formulas:
[OAC 252:100-43]

$$lb/MMBtu =$$

$$\frac{1}{365}\sum_{n=1}^{365}\left((F_d)_n(ppmvd)_n\left(\frac{1}{10^6}\right)\left(\frac{20.9}{20.9-(O_2)_n}\right)\left(\frac{46.0\ lb\ NO_2}{lb-mol}\right)\left(\frac{1\ lb-mol}{379.4\ Scf}\right)\right)$$

where F_d = Daily average ratio of combustion gas volume to heat input, dscf/10^6 Btu;
O_2 = Daily average oxygen concentration, %;

ppmvd = Daily average NO_X concentration in the gas (dry, volume basis); and
n = Each day.

h. For listed equipment with a rated heat input of 50 MMBtu/hr or more constructed, altered, replaced, or rebuilt resulting in an increase in emissions of NO_X after February 14, 1972, the NO_X emission rate is limited to 0.20 lb/MMBtu, 3-hour average calculated from 3 contiguous hours each hour for any period with 3 hours of complete data.
[OAC 252:100-33]

i. Compliance of boiler B-0022 with the NO_X and CO lb/MMBtu emission limits shall be via performance test. [OAC 252:100-8-6(a)]

j. Boiler B-0022 shall demonstrate compliance with the SO_2 emission limits by combusting only pipeline grade natural gas. [OAC 252:100-31]

k. Within 60 days of achieving maximum firing rate from boiler B-0022, not to exceed 180 days from initial startup, and at other such times as directed by Air Quality, the permittee shall conduct performance testing for NO_X and CO and furnish a written report to Air Quality documenting compliance with emission limitations. Performance testing by the permittee shall use the following test methods specified in 40 CFR Part 60:

   i. Method 1: Sample and Velocity Traverses for Stationary Sources.

   ii. Method 2: Determination of Stack Gas Velocity and Volumetric Flow rate

   iii. Method 3 or 3A: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.

   iv. Method 4: Determination of Moisture in Stack gases.

   v. Method 7E: Determination of Nitrogen Oxide Emissions from Stationary Sources.

   vi. Method 10: Determination of Carbon Monoxide Emissions from Stationary Sources.

   vii. Method 19: F-factor Methodology

l. Reserved.

m. Boiler B-0022 is subject to 40 CFR Part 60 Subpart Dc. The permittee shall comply with all applicable requirements including, but not limited to, the following:
[40 CFR Part 60 Subpart Dc]

   i. §60.48c Reporting and recordkeeping requirements.

n. Reserved.

o. Boiler B-0021 was permanently removed from service by June 2012 and shall not be returned to service.

p. The boilers are subject to 40 CFR Part 63 Subpart DDDDD. The permittee shall comply with all applicable requirements including, but not limited to, the following:

[40 CFR Part 63 Subpart DDDDD]

i. §63.7495 When Do I Have To Comply With This Subpart?

ii. §63.7500 What Emission Limits, Work Practice Standards, And Operating Limits Must I Meet?

iii. §63.7505 What Are My General Requirements For Complying With This Subpart?

iv. §63.7510 What Are My Initial Compliance Requirements And By What Date Must I Conduct Them?

v. §63.7515 When Must I Conduct Subsequent Performance Tests, Fuel Analyses, Or Tune-Ups?

vi. §63.7530 How Do I Demonstrate Initial Compliance With The Emission Limitations, Fuel Specifications And Work Practice Standards?

vii. §63.7540 How Do I Demonstrate Continuous Compliance With The Emission Limitations, Fuel Specifications And Work Practice Standards?

viii. §63.7545 What Notifications Must I Submit And When?

ix. §63.7550 What Reports Must I Submit And When?

x. §63.7555 What Records Must I Keep?

xi. §63.7560 In What Form And How Long Must I Keep My Records?

EUG HTR-2: 40 CFR Part 60 Subpart J and 40 CFR Part 63 Subpart DDDDD Heaters & Boilers

EU ID	Point ID	Const/ Mod Date	Fired Duty Limit (1) (MMBtu/hr)	Pollutant	Emission Rate Limit (1) (lb/MMBtu)	Emission Limit (1)	
						lb/hr	TPY
B-0006	Permanently removed from service by July 31, 2009 and shall not be returned to service.						
B-0007							
B-5004	Permanently removed from service by December 31, 2022 and shall not be returned to service.						
H-0001	Permanently removed from service by September 24, 2017 and shall not be returned to service						

EU ID	Point ID	Const/ Mod Date	Fired Duty Limit [1] (MMBtu/hr)	Pollutant	Emission Rate Limit [1] (lb/MMBtu)	Emission Limit [1]	
						lb/hr	TPY
H-0003	H-0003	1929 / 2002 (SC 31 & NSPS Mod)	32	NO_X	-	3.2	13.8
				CO	-	1.3	5.5
				SO_2	-	0.3	1.4
				VOC	-	0.2	0.8
				PM_{10}	-	0.2	1.0
H-0004	H-0004	1945 / 2002 (SC 31, 33 & NSPS mod)	118	NO_X	- 0.20[7]	15.5	65.6
				CO	-	4.6	20.1
				SO_2	-	1.2	5.1
				VOC	-	0.6	2.8
				PM_{10}	-	0.9	3.9
H-0005	Permanently removed from service by September 24, 2017 and shall not be returned to service.						
H-0010	H-0010	1972 (SC 33)	55 [3]	NO_X	- 0.20[7]	5.4 -	23.6 -
				CO	-	4.5	19.9
				SO_2	-	1.7	7.5
				VOC	-	0.3	1.3
				PM_{10}	-	0.4	1.8
H-0011	H-0011	1988	18	NO_X	-	2.2	9.5
				CO	-	1.5	6.5
				SO_2	-	0.2	0.8
				VOC	-	0.1	0.4
				PM_{10}	-	0.1	0.6
H-0016	H-0016	2004 (SC 33)	107 [3]	NO_X	0.035/ 0.20[7]	3.7 -	16.4 -
				CO	-	4.3	18.7
				SO_2	-	3.3	14.5
				VOC	-	0.6	2.5
				PM_{10}	-	0.8	3.5
H-0023	H-0023	1984 (SC 33)	52.4	NO_X	- 0.20[7]	7.2 -	31.4 -
				CO	-	4.3	18.9
				SO_2	-	1.6	7.1
				VOC	-	0.3	1.2
				PM_{10}	-	0.4	1.7
H-0028	H-0028/ 0029	1954	129 [3]	NO_X	-	-	78.0
				CO	-	-	47.0
				SO_2	-	4.0	17.5
				VOC	-	-	-
				PM_{10}	-	-	5.0

EU ID	Point ID	Const/ Mod Date	Fired Duty Limit [1] (MMBtu/hr)	Pollutant	Emission Rate Limit [1] (lb/MMBtu)	Emission Limit [1]	
						lb/hr	TPY
H-0029	H-0028/ 0029	1983 (SC 33)	75	NO_X	- 0.20[7]	7.4 -	32.2 -
				CO	-	6.2	27.1
				SO_2	-	2.3	10.2
				VOC	-	0.4	1.8
				PM_{10}	-	0.6	2.4
H-0046	H-0046	1964	48 [3]	NO_X	-	-	21.0
				CO	-	-	18.0
				SO_2	-	1.5	6.5
				VOC	-	-	-
				PM_{10}	-	-	2.0
H-0048	H-0048	1957	241.4	NO_X	0.070	16.9	74.0
				CO	0.040 [1]/ 0.060 [2][8]/ 0.080 [4]/ 400 [5]	9.7 - - -	42.3 - - -
				SO_2	-	7.5	32.7
				VOC	-	1.3	5.7
				PM_{10}	-	1.8	7.9
H-0057 H-0058 H-0059	Permanently removed from service by February 28, 2009 and shall not be returned to service.						
H-1001	H-1001	2005	30[3]	NO_X	0.050	1.5	6.6
				CO	-	1.2	5.3
				SO2	-	0.9	4.1
				VOC	-	0.2	0.7
				PM_{10}	-	0.2	1.0
H-5001	Permanently removed from service by December 18, 2008 and shall not be returned to service.						
H-6005	H-6005	1997 (SC 33)	170[3]	NO_X	- 0.20[7]	11.8 -	51.6 -
				CO	-	12.9	56.4
				SO_2	-	4.9	21.3
				VOC	-	0.9	3.8
				PM_{10}	-	1.2	5.2
H-6007	H-6007	1956 / 1990 (SC 31 & 33 mod)	150	NO_X	0.065/ 0.20[7]	9.7 -	42.7 -
				CO	0.040 [1]/ 0.060 [2][8]/ 0.080 [4]/ 400 [5]	6.0 - - -	26.3 - - -
				SO_2	-	4.7	20.4
				VOC	-	0.8	3.5
				PM_{10}	-	1.1	4.9

EU ID	Point ID	Const/ Mod Date	Fired Duty Limit (1) (MMBtu/hr)	Pollutant	Emission Rate Limit (1) (lb/MMBtu)	Emission Limit (1)	
						lb/hr	TPY
H-6008	H-6008	1955	2.0	NO_X	-	-	1.0
				CO	-	-	1.0
				SO_2	-	0.1	0.3
				VOC	-	-	-
				PM_{10}	-	-	1.0
H-6012	H-6012	1971	25 (3)	NO_X	-	-	11.0
				CO	-	-	9.0
				SO_2	-	0.8	3.4
				VOC	-	-	-
				PM_{10}	-	-	1.0
H-6013	H-6013	2002 (SC 33)	75.8 (3)	NO_X	- 0.20(7)	4.6 -	19.9 -
				CO	-	-	-
				SO_2	-	2.3	10.3
				VOC	-	-	-
				PM_{10}	-	-	-
H-6014	H-6014	1978 (SC 33)	72	NO_X	0.050/ 0.20(7)	3.6 -	15.8 -
				CO	0.040 (1)/ 0.060 (2)(8)/ 0.080 (4)	2.9 - -	12.6 - -
				SO_2	-	2.2	9.8
				VOC	-	0.4	1.7
				PM_{10}	-	0.5	2.3
H-6015	H-6015	1980 (SC 33)	79	NO_X	0.060/ 0.20(7)	4.8 -	20.8 -
				CO	0.040 (1)/ 0.060 (2)(8)/ 0.080 (4)	3.2 - -	13.8 - -
				SO_2	-	2.4	10.7
				VOC	-	0.4	1.8
				PM_{10}	-	0.6	2.6
H-6151	H-6151	1958	80 (3)	NO_X	-	-	34.3
				CO	-	-	28.9
				SO_2	-	2.5	10.9
				VOC	-	-	-
				PM_{10}	-	-	2.6
H-7501	H-7501	1991	41 (3)	NO_X	-	4.1	18.0
				CO	-	1.2	5.4
				SO_2	-	1.1	5.0
				VOC	-	0.2	1.0
				PM_{10}	-	0.3	1.3

EU ID	Point ID	Const/ Mod Date	Fired Duty Limit [1] (MMBtu/hr)	Pollutant	Emission Rate Limit [1] (lb/MMBtu)	Emission Limit [1]	
						lb/hr	TPY
H-8601	H-8601	2003 (Pre 12/13/03) (SC 33)	120	NO_X	0.035/ 0.20[7]	4.2 -	18.4 -
				CO	-	9.9	43.3
				SO_2	-	3.7	16.3
				VOC	-	0.7	2.9
				PM_{10}	-	0.9	3.9
H-8602	H-8602	2003 (Pre 12/13/03)	36	NO_X	0.035	1.3	5.5
				CO	-	3.0	13.0
				SO_2	-	1.1	4.9
				VOC	-	0.2	0.8
				PM_{10}	-	0.3	1.2
H-8801/ 8802	H-8801/ 8802	2003 (Pre 12/13/03) (SC 33)	123	NO_X	0.035/ 0.20[7]	4.3 -	18.9 -
				CO	-	10.1	44.2
				SO_2	-	0.1	0.3
				VOC	-	0.7	2.9
				PM_{10}	-	0.9	4.0
H-9851	H-9851	2005 (SC 33)	282 [3]	NO_X	0.075/ 0.20[7]	21.2 -	92.8 -
				CO	-	11.3	49.5
				SO_2	-	8.7	38.3
				VOC	-	1.5	6.7
				PM_{10}	-	2.1	9.3
H-9901	H-9901	2005	40 [3]	NO_X	0.050	2.0	8.8
				CO	-	1.6	7.0
				SO_2	-	1.2	5.4
				VOC	-	0.2	1.0
				PM_{10}	-	0.3	1.3
H-9902	H-9902	2005 (SC 33)	50 [3]	NO_X	0.050/ 0.20[7]	2.5 -	11.0 -
				CO	-	2.0	8.8
				SO_2	-	1.6	6.8
				VOC	-	0.3	1.2
				PM_{10}	-	0.4	1.6

1. 365-day rolling average, except as otherwise specified in the specific conditions. Time period basis is midnight to midnight (does not include lb/MMBTU limit under NSPS Subpart J or OAC 252:100-33).
2. 24-hr rolling average limit calculated hourly on the hour. Limit does not apply during low fired duty and catalyst regeneration. Low fired duty is less than 30% of max firing rate and applies to H-0048, H-6007, H-6014, and H-6015 only. Catalyst regeneration applies to H-0048 and H-6007 only. CO emissions during startup, shutdown, or malfunction will not be used for determining compliance with the 24-hr rolling average limit provided that the facility implements good air pollution control practices to minimize emissions during such periods.
3. Fired duties are shown for the purposes of regulatory applicability only and are not limits.

4. 7-day rolling average limit during low fired duty only. Time period basis is midnight to midnight. Limit does not apply during catalyst regeneration. Low fired duty is less than 30% of max firing rate and applies to H-0048, H-6007, H-6014, and H-6015 only. Catalyst regeneration applies to H-0048 and H-6007 only. CO emissions during startup, shutdown, or malfunction will not be used for determining compliance with the 7-day rolling average limit provided that the facility implements good air pollution control practices to minimize emissions during such periods.
5. ppmvd @ 3% O_2 7-day rolling average limit during catalyst regeneration only. Catalyst regeneration applies to H-0048 and H-6007 only. Limit does not apply during startup, shutdown or malfunction. Time period basis is midnight to midnight.
6. Reserved.
7. Based on 3-hour average (from 3 contiguous 1-hour periods) calculated each clock hour.
8. For clock hours when the heater is not operating, no values shall be used to calculate averages and those periods shall be skipped in determining the 24-hour average.

a. The heaters and boilers are subject to 40 CFR Part 60 Subpart J. The permittee shall comply with all applicable requirements including, but not limited to, the following:

[40 CFR Part 60 Subpart J]

i. §60.104 Standards for sulfur oxides. The heaters and boilers shall combust only pipeline grade natural gas, PSA off-gas, or refinery fuel gas with a 3-hour rolling average maximum H_2S concentration of 0.1 gr/dscf (160 ppmv @ 60°F).

ii. §60.105 Monitoring of emissions and operations. A continuous monitoring system shall be operated and maintained to record either the H_2S content of the fuel gas or the SO_2 concentration in the flue gas. If an SO_2 monitor is used, the SO_2 concentration standard is 20 ppmvd @ 0% O_2, 3-hr rolling average and an oxygen monitor shall also be included for correcting the data for excess air.

iii. §60.106 Test methods and procedures.

iv. §60.107 Reporting and recordkeeping requirements.

v. §60.108 Performance test and compliance provisions

b. Compliance with the firing rate limits for H-0003, H-0004, H-0011, H-0023, H-0029, H-0048, H-6007, H-6008, H-6014, H-6015, H-8601, H-8602, and H-8801/8802 shall be based on 365-day rolling averages, with each day calculated based on daily fuel gas usage and weekly heating value, and shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula:

[OAC 252:100-43]

$$MMBtu/hr = \frac{1}{365}\sum_{n=1}^{365}\left((MMSCFD)_n(Btu/Scf\ (HHV))_n\left(\frac{1\ day}{24\ hours}\right)\right)$$

where MMSCFD = Daily fuel gas usage;
Btu/Scf (HHV) =Gas heating value (high heat value), determined weekly; and
n = Each day.

c. Compliance with the emissions limits for PM and VOC is demonstrated by the use of good combustion practices. [OAC 252:100-43]

d. Compliance with the SO_2 lb/hr and TPY emission limits shall be based on 365-day rolling averages and 365-day rolling totals, respectively, with each day calculated based on the daily fuel gas usage and H_2S content, and shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formulas: [OAC 252:100-43]

$$\frac{lb}{hr} = \frac{1}{365}\sum_{n=1}^{365}\left((MMSCFD)_n(ppmvd\ H_2S)_n\left(\frac{64\ lb\ SO_2}{lb-mol}\right)\left(\frac{1\ day}{24\ hours}\right)\left(\frac{1\ lb-mol}{379.4\ Scf}\right)\right)$$

$$TPY = \sum_{n=1}^{365}\left((MMSCFD)_n(ppmvd\ H_2S)_n\left(\frac{64\ lb\ SO_2}{lb-mol}\right)\left(\frac{1\ ton}{2{,}000\ lb}\right)\left(\frac{1\ lb-mol}{379.4\ Scf}\right)\right)$$

where MMSCFD = Daily fuel gas usage;
ppmvd H_2S = Daily average hydrogen sulfide concentration (dry, volume basis); and
n = Each day.

e. Compliance with the NO_X and CO lb/hr and TPY emission limits (excluding the emission limits of 40 CFR Part 60, Subpart J, 40 CFR Part 63, Subpart DDDDD, and OAC 252:100-33) shall be based on 365-day rolling averages and 365-day rolling totals, respectively, with each day calculated based on heater specific (stack test) emission factors and the daily fuel gas usage and weekly heating value, CEMS when available, or the most current version of AP-42 emission factors from Table 1.4-1. Compliance shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formulas: [OAC 252:100-43]

$$\frac{lb}{hr} = \frac{1}{365}\sum_{n=1}^{365}\left((MMSCFD)_n(Btu/Scf\ (HHV))_n(EF)\left(\frac{1\ day}{24\ hours}\right)\right)$$

$$TPY = \sum_{n=1}^{365}\left((MMSCFD)(Btu/Scf\ (HHV))(EF)\left(\frac{1\ ton}{2{,}000\ lb}\right)\right)$$

where EF = Emission factor, lb/MMBtu;
MMSCFD = Daily fuel gas usage;
Btu/Scf (HHV) = Gas heating value (high heat value), determined weekly; and
n = Each day.

f. For those boilers or heaters equipped with a NO_X CEMS, compliance with the NO_X lb/MMBtu emission limit (excluding the emission limits of 40 CFR Part 60, Subpart J and OAC 252:100-33) shall be based on 365-day rolling averages, with each day calculated using the daily average CEMS data for the NO_X concentration in the flue gas. Compliance shall be

demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula: [OAC 252:100-43]

$$lb/MMBtu =$$

$$\frac{1}{365}\sum_{n=1}^{365}\left((F_d)_n(ppmvd)_n\left(\frac{1}{10^6}\right)\left(\frac{20.9}{20.9-(O_2)_n}\right)\left(\frac{46.0\ lb\ NO_2}{lb-mol}\right)\left(\frac{1\ lb-mol}{379.4\ Scf}\right)\right)$$

where F_d = Daily average ratio of combustion gas volume to heat input, dscf/10^6 Btu;
O_2 = Daily average oxygen concentration, %;
ppmvd = Daily average NO_X concentration in the gas (dry, volume basis); and
n = Each day.

Otherwise, compliance with the NO_X lb/MMBtu emission limit shall be demonstrated through initial performance testing.

g. For those boilers or heaters equipped with a CO CEMS, compliance with the CO lb/MMBtu emission limit or concentration limit shall be based on 365-day rolling averages (or 24-hr or 7-day rolling average as applicable), with each day calculated using the daily average CEMS data for CO concentration in the flue gas. Compliance shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula: [OAC 252:100-43]

$$lb/MMBtu =$$

$$\frac{1}{365}\sum_{n=1}^{365}\left((F_d)_n(ppmvd)_n\left(\frac{1}{10^6}\right)\left(\frac{20.9}{20.9-(O_2)_n}\right)\left(\frac{28.0\ lb\ NO_2}{lb-mol}\right)\left(\frac{1\ lb-mol}{379.4\ Scf}\right)\right)$$

where F_d = Daily average ratio of combustion gas volume to heat input, dscf/10^6 Btu;
O_2 = Daily average oxygen concentration, %;
ppmvd = Daily average CO concentration in the gas (dry, volume basis); and
n = Each day.

Otherwise, compliance with the CO lb/MMBtu emission limit shall be demonstrated through initial performance testing.

h. Reserved.

i. Reserved.

j. Reserved.

k. Within 180 days of commencement of operation of Ultra Low NO_X burners installed in H-0048, H-6007, and H-6015, the permittee shall certify, calibrate, maintain and operate NO_X and CO Continuous Emission Monitoring Systems (CEMS) in accordance with the

requirements of 40 CFR §§60.11, 60.13, and Part 60 Appendix A, B, and F. With respect to 40 CFR Part 60, Appendix F, in lieu of the requirements of 40 CFR Appendix F sections 5.1.1, 5.1.3, and 5.1.4, the permittee shall conduct either a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) once every twelve calendar quarters, provided that a cylinder gas audit is conducted each calendar quarter.

l. Heater H-5002 replaced existing heater H-5001, which was removed from service by December 18, 2008, and shall not be returned to service. Heater H-0060 replaced heaters H-0057, H-0058, and H-0059, which were removed from service by February 28, 2009, and shall not be returned to service. Heater H-0001 (275 MMBtu/hr) replaced smaller H-0001 (175 MMBtu/hr), which was removed from service by September 24, 2017, and shall not be returned to service. [OAC 252:100-8-6(a)]

m. For listed equipment with a rated heat input of 50 MMBtu/hr or more constructed, altered, replaced, or rebuilt resulting in an increase of emissions of NO_X after February 14, 1972, the NO_X emission rate is limited to 0.20 lb/MMBtu, 3-hour average calculated from 3 contiguous hours each hour for any periods with 3 hours of complete data. [OAC 252:100-33]

n. The heaters and boilers are subject to 40 CFR Part 63 Subpart DDDDD. The permittee shall comply with all applicable requirements including, but not limited to, the following: [40 CFR Part 63 Subpart DDDDD]

i. §63.7495 When Do I Have To Comply With This Subpart?

ii. §63.7500 What Emission Limits, Work Practice Standards, And Operating Limits Must I Meet?

iii. §63.7505 What Are My General Requirements For Complying With This Subpart?

iv. §63.7510 What Are My Initial Compliance Requirements And By What Date Must I Conduct Them?

v. §63.7515 When Must I Conduct Subsequent Performance Tests, Fuel Analyses, Or Tune-Ups?

vi. §63.7530 How Do I Demonstrate Initial Compliance With The Emission Limitations, Fuel Specifications And Work Practice Standards?

vii. §63.7540 How Do I Demonstrate Continuous Compliance With The Emission Limitations, Fuel Specifications And Work Practice Standards?

viii. §63.7545 What Notifications Must I Submit And When?

ix. §63.7550 What Reports Must I Submit And When?

x. §63.7555 What Records Must I Keep?

xi. §63.7560 In What Form And How Long Must I Keep My Records?

EUG HTR-2.1: 40 CFR Part 60 Subpart Ja and 40 CFR Part 63 Subpart DDDDD Heaters & Boilers

EU ID	Point ID	Construction/ Modification Date	Fired Duty Limit[2] (MMBtu/hr)	Pollutant	Emission Rate Limit[1] (lb/MMBtu)	Emission Limits[1]	
						lb/hr	TPY
H-0001	H-0001	2017	275	NO_X	0.05 0.20[3]	13.8 -	60.2 -
				CO	--	11.0	48.2
				SO_2	--	3.2	14.1
				VOC	--	1.5	6.5
				PM_{10}	--	2.1	9.0
H-0060	H-0060	2008	147	NO_X	0.05/ 0.20[3]	6.4 -	28.0 -
				CO	–	5.1	22.4
				SO_2	–	4.0	17.4
				VOC	–	0.8	3.4
				PM_{10}	–	1.1	4.8
H-9301	H-9301	2010	131	NO_X	0.03 0.20[3]	3.94 -	17.3 -
				CO	0.04	5.25	23.0
				SO_2	--	1.58	6.9
				VOC	--	0.71	3.1
				PM_{10}	--	0.98	4.3
H-5002	H-5002	2008	120	NO_X	0.040 0.20[3]	4.8 -	21.0 -
				CO	–	4.8	21.0
				SO_2	–	3.7	16.3
				VOC	–	0.7	2.9
				PM_{10}	–	0.9	3.9

1. 365-day rolling average. Time period basis is midnight-to-midnight (does not include lb/MMBTU limit under NSPS Subpart Ja or OAC 252:100-33).
2. Fired duty is shown for the purposes of regulatory applicability only and is not a permit limit.
3. Based on 3-hour average (from 3 contiguous 1-hour periods) calculated each clock hour.

a. These heaters are subject to 40 CFR Part 60 Subpart Ja, and shall comply with any and all applicable requirements, including but not limited to: [40 CFR Part 60 Subpart Ja]

i. §60.100a Applicability, designation of affected facility, and reconstruction.

ii. §60.101a Definitions.

iii. §60.102a Emissions limitations. The heaters shall combust only pipeline grade natural gas, PSA off-gas, or refinery fuel gas.

iv. §60.103a Work practice standards.

v. §60.104a Performance tests.

vi. §60.107a Monitoring of emissions and operations for fuel gas combustion. Continuous monitoring systems shall be operated and to record H_2S content of the fuel gas.

vii. §60.108a Recordkeeping and reporting requirements.

viii. §60.109a Delegation of authority.

b. Compliance with the SO_2 lb/hr and TPY emission limits shall be based on 365-day rolling averages and 365-day rolling totals, respectively, with each day calculated based on the daily fuel gas usage and H_2S content, and shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formulas:

[OAC 252:100-43]

$$\frac{lb}{hr} = \frac{1}{365}\sum_{n=1}^{365}\left((MMSCFD)_n(ppmvd\ H_2S)_n\left(\frac{64\ lb\ SO_2}{lb-mol}\right)\left(\frac{1\ day}{24\ hours}\right)\left(\frac{1\ lb-mol}{379.4\ Scf}\right)\right)$$

$$TPY = \sum_{n=1}^{365}\left((MMSCFD)_n(ppmvd\ H_2S)_n\left(\frac{64\ lb\ SO_2}{lb-mol}\right)\left(\frac{1\ ton}{2{,}000\ lb}\right)\left(\frac{1\ lb-mol}{379.4\ Scf}\right)\right)$$

where MMSCFD = Daily fuel gas usage;
ppmvd H_2S = Daily average hydrogen sulfide concentration (dry, volume basis); and
n = Each day.

c. Compliance with the NO_X and CO lb/hr and TPY emission limits shall be based on 365-day rolling averages and 365-day rolling totals, respectively, with each day calculated based on heater specific (stack test) emission factors and the daily fuel gas usage and weekly heating value, CEMS when available, or the most current version of AP-42 emission factors from Table 1.4-1. Compliance shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formulas:

[OAC 252:100-43]

$$\frac{lb}{hr} = \frac{1}{365}\sum_{n=1}^{365}\left((MMSCFD)_n(Btu/Scf\ (HHV))_n(EF)\left(\frac{1\ day}{24\ hours}\right)\right)$$

$$TPY = \sum_{n=1}^{365}\left((MMSCFD)(Btu/Scf\ (HHV))(EF)\left(\frac{1\ ton}{2{,}000\ lb}\right)\right)$$

where EF = Emission factor, lb/MMBtu;
MMSCFD = Daily fuel gas usage;
Btu/Scf (HHV) = Gas heating value (high heat value), determined weekly; and
n = Each day.

d. For heaters equipped with a NO_X CEMS, compliance with the NO_X lb/MMBtu emission limit (excluding the emission limits of 40 CFR Part 60, Subpart Ja and OAC 252:100-33) shall be based on 365-day rolling averages, with each day calculated using the daily average CEMS data for NO_X concentration in the flue gas. Compliance shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula:
[OAC 252:100-43]

$$lb/MMBtu =$$

$$\frac{1}{365}\sum_{n=1}^{365}\left((F_d)_n(ppmvd)_n\left(\frac{1}{10^6}\right)\left(\frac{20.9}{20.9-(O_2)_n}\right)\left(\frac{46.0\ lb\ NO_2}{lb-mol}\right)\left(\frac{1\ lb-mol}{379.4\ Scf}\right)\right)$$

where F_d = Daily average ratio of combustion gas volume to heat input, dscf/10^6 Btu;
O_2 = Daily average oxygen concentration, %;
ppmvd = Daily average NO_X concentration in the gas (dry, volume basis); and
n = Each day.

Otherwise, compliance with the NO_X lb/MMBtu emission limit shall be demonstrated through initial performance testing.

e. For heaters equipped with a CO CEMS, compliance with the CO lb/MMBtu emission limit or concentration limit shall be based on 365-day rolling averages (or 24-hr or 7-day rolling average as applicable), with each day calculated using the daily average CEMS data for CO concentration in the flue gas. Compliance shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula:
[OAC 252:100-43]

$$lb/MMBtu =$$

$$\frac{1}{365}\sum_{n=1}^{365}\left((F_d)_n(ppmvd)_n\left(\frac{1}{10^6}\right)\left(\frac{20.9}{20.9-(O_2)_n}\right)\left(\frac{28.0\ lb\ NO_2}{lb-mol}\right)\left(\frac{1\ lb-mol}{379.4\ Scf}\right)\right)$$

where F_d = Daily average ratio of combustion gas volume to heat input, dscf/10^6 Btu;
O_2 = Daily average oxygen concentration, %;
ppmvd = Daily average CO concentration in the gas (dry, volume basis); and
n = Each day.

Otherwise, compliance with the CO lb/MMBtu emission limit shall be demonstrated through initial performance testing.

f. Heater H-5002 replaced existing heater H-5001, which was removed from service by December 18, 2008, and shall not be returned to service. Heater H-0060 replaced heaters H-0057, H-0058, and H-0059, which were removed from service by February 28, 2009, and shall not be returned to service. H-0001 (275 MMBtu/hr) replaced existing heater H-0001 (175 MMBtu/hr), which was removed from service by September 24, 2017, and shall not be returned to service. [OAC 252:100-8-6(a)]

g. For listed equipment with a rated heat input of 50 MMBtu/hr or more constructed, altered, replaced, or rebuilt resulting in an increase of emissions of NO_X after February 14, 1972, the NO_X emission rate is limited to 0.20 lb/MMBtu, 3-hour rolling average calculated from 3 contiguous hours each hour for any period with 3 hours of complete data. [OAC 252:100-33]

h. Heater H-0001 shall be constructed with air preheater and balanced draft systems.

i. The heaters are subject to 40 CFR Part 63 Subpart DDDDD. The permittee shall comply with all applicable requirements including, but not limited to, the following: [40 CFR Part 63 Subpart DDDDD]

   i. §63.7495 When Do I Have To Comply With This Subpart?

   ii. §63.7500 What Emission Limits, Work Practice Standards, And Operating Limits Must I Meet?

   iii. §63.7505 What Are My General Requirements For Complying With This Subpart?

   iv. §63.7510 What Are My Initial Compliance Requirements And By What Date Must I Conduct Them?

   v. §63.7515 When Must I Conduct Subsequent Performance Tests, Fuel Analyses, Or Tune-Ups?

   vi. §63.7530 How Do I Demonstrate Initial Compliance With The Emission Limitations, Fuel Specifications And Work Practice Standards?

   vii. §63.7540 How Do I Demonstrate Continuous Compliance With The Emission Limitations, Fuel Specifications And Work Practice Standards?

   viii. §63.7545 What Notifications Must I Submit And When?

   ix. §63.7550 What Reports Must I Submit And When?

   x. §63.7555 What Records Must I Keep?

   xi. §63.7560 In What Form And How Long Must I Keep My Records?

EUG HTR-2.2 Boilers Subject to 40 CFR Part 63 Subpart DDDDD

EU ID	Point ID	Const/ Mod Date	Fired Duty (1) MMBtu/hr	Pollutant	Emission Rate Limit (lb/MMBtu)	Emission Limit	
						lb/hr	TPY
BLR-GFMRW1	BLR-GFMRW1	11/13/1978	20.9	NO_X	--	--	--
				CO	--	--	--
				SO_2	--	--	--
				VOC	--	--	--
				PM_{10}	--	--	--
BLR-GFMRW3	BLR-GFMRW3	11/13/1978	20.9	NO_X	--	--	--
				CO	--	--	--
				SO_2	--	--	--
				VOC	--	--	--
				PM_{10}	--	--	--
BLR-GFMRW4	BLR-GFMRW4	2/25/1982	14.6	NO_X	--	--	--
				CO	--	--	--
				SO_2	--	--	--
				VOC	--	--	--
				PM_{10}	--	--	--
BLR-GFMRW5	BLR-GFMRW5	2/25/1982	14.6	NO_X	--	--	--
				CO	--	--	--
				SO_2	--	--	--
				VOC	--	--	--
				PM_{10}	--	--	--
BLR-GFMRW6	BLR-GFMRW6	2/25/1982	14.6	NO_X	--	--	--
				CO	--	--	--
				SO_2	--	--	--
				VOC	--	--	--
				PM_{10}	--	--	--

1. Fired duty is shown for the purposes of regulatory applicability only and is not a limit.

a. The boilers are subject to 40 CFR Part 63 Subpart DDDDD. The permittee shall comply with all applicable requirements including, but not limited to, the following:

[40 CFR Part 63 Subpart DDDDD]

i. §63.7495 When Do I Have To Comply With This Subpart?

ii. §63.7500 What Emission Limits, Work Practice Standards, And Operating Limits Must I Meet?

iii. §63.7505 What Are My General Requirements For Complying With This Subpart?

iv. §63.7510 What Are My Initial Compliance Requirements And By What Date Must I Conduct Them?

v. §63.7515 When Must I Conduct Subsequent Performance Tests, Fuel Analyses, Or Tune-Ups?

vi. §63.7530 How Do I Demonstrate Initial Compliance With The Emission Limitations, Fuel Specifications And Work Practice Standards?

vii. §63.7540 How Do I Demonstrate Continuous Compliance With The Emission Limitations, Fuel Specifications And Work Practice Standards?

viii. §63.7545 What Notifications Must I Submit And When?

ix. §63.7550 What Reports Must I Submit And When?

x. §63.7555 What Records Must I Keep?

xi. §63.7560 In What Form And How Long Must I Keep My Records?

EUG HTR-3: Heaters & Boilers Subject to Oklahoma Rules or Permit Limits

EU ID	Point ID	Const/ Mod Date	Fired Duty (1) MMBtu/hr	Pollutant	Emission Rate Limit (lb/MMBtu)	Emission Limit	
						lb/hr	TPY
H-6037A/ 6037B	No. 4 FCCU	1988	23.4	NO_X	-	(2)	(2)
				CO	-	(2)	(2)
				SO_2	-	(2)	(2)
				VOC	-	(2)	(2)
				PM_{10}	-	(2)	(2)
HTR-5FCC Converter Air Preheater	No. 5 FCCU	1971	Est. >10 but <50	NO_X	-	(3)	(3)
				CO	-	(3)	(3)
				SO_2	-	(3)	(3)
				VOC	-	(3)	(3)
				PM_{10}	-	(3)	(3)

1. Fired duty is shown for the purposes of regulatory applicability only and is not a limit.
2. H-6037A/6037B emissions are included in the No. 4 FCCU emission limits.
3. HTR-5FCC Converter Air Preheater emissions are included in the No. 5 FCCU emission limits.

EUG HTR-4: Insignificant Activity Heaters & Boilers

There are no emissions limitations for these heaters or boilers.

EU ID	Point ID	Equipment	Insignificant Activity Reason
BLR-GFMNT1	BLR-GFMNT1	North Tower Emergency Boiler	App. I: Combustion Equipment-Commercial Nat. Gas < 5 MMBtu/hr
BLR-GFMPB1	BLR-GFMPB1	Park Bldg Boiler #1	App. I: Combustion Equipment-Commercial Nat. Gas < 5 MMBtu/hr
BLR-GFMPB2	BLR-GFMPB2	Park Bldg Boiler #2	App. I: Combustion Equipment-Commercial Nat. Gas < 5 MMBtu/hr

EU ID	Point ID	Equipment	Insignificant Activity Reason
BLR-GFMST1	BLR-GFMST1	South Tower Emergency Boiler [Diesel Fired]	App. I: Activities having the potential to emit no more than 5 TPY [actual] of any pollutant.

MISCELLANEOUS EQUIPMENT

EUG ENG: Engines

a. The permittee is authorized to replace any internal combustion engine or turbine with emissions limitations specified in this permit with an engine or turbine that meets the following requirements: [OAC 252:100-8-6(f)]

i. The permittee shall notify AQD in writing at least seven days in advance of the replacement. Said notice shall include the new engine/turbine make and model, horsepower rating, fuel usage, stack flow (ACFM), stack temperature (^{o}F), and rates (g/hp-hr, lb/hr, and TPY) at maximum rated horsepower for the altitude/location.

ii. The replacement engine or turbine shall comply with the same emissions limits as the engine or turbine that it replaced. This applies to lb/hr and TPY limits specified in this permit.

iii. The authorization of replacement of an engine or turbine includes temporary periods of 6 months or less for maintenance purposes.

iv. The permittee shall notify AQD in writing not later than 7 days prior to start-up of the replacement engine or turbine. Said notice shall identify the old engine/turbine and shall include the new engine/turbine make and model, serial number, horsepower rating, and pollutant emission rates (g/hp-hr, lb/hr, and TPY) at maximum horsepower for the altitude/location.

v. Quarterly emissions tests for the replacement engine(s)/turbine(s) shall be conducted to confirm continued compliance with NO_X and CO emission limitations. A copy of the first quarter testing shall be provided to AQD within 60 days of start-up of each replacement engine/turbine. The test report shall include the engine/turbine fuel usage, stack flow (ACFM), stack temperature (°F), and pollutant emission rates (g/hp-hr, lbs/hr, and TPY) at maximum rated horsepower for the altitude/location.

vi. Replacement equipment and emissions are limited to equipment and emissions which are not a modification under NSPS or NESHAP.

vii. Replacement equipment and emissions are limited to equipment and emissions which are not a modification or a significant modification under PSD. For existing PSD facilities, the permittee shall calculate the PTE or the net emissions increase resulting from the replacement to document that it does not exceed significance levels and

submit the results with the notice required by paragraph (c) of this Specific Condition. The permittee shall attach each such notice to their copy of the relevant permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield described in OAC 252:100-8-6(d) does not apply to any change made pursuant to this paragraph.

viii. Engines whose installation and operation are authorized under this Specific Condition which are subject to 40 CFR Part 63, Subpart ZZZZ and/or 40 CFR Part 60, Subpart IIII or Subpart JJJJ shall comply with all applicable requirements.

ix. Turbines whose installation and operation are authorized under this Specific Condition which are subject to 40 CFR Part 60, Subpart KKKK shall comply with all applicable requirements.

b. As an alternative to (a) above, and only for the rental/portable emergency engines listed below, replacement is allowed provided the replacement meets conditions i to x:

EU	Point	Make/Model	HP	Installed Date
ENG-EPIAB	ENG-EPIAB	TBD	TBD	TBD
ENG-ALKY	ENG-ALKY	TBD	TBD	TBD
ENG-SPIAB	ENG-SPIAB	TBD	TBD	TBD

i. Does not violate any applicable requirement, or state-only requirements;

ii. Does not involve significant changes to existing monitoring, reporting or recordkeeping requirements in the permit;

iii. Does not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;

iv. Does not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement or state-only requirement which the source has assumed to avoid some other applicable requirement or state-only requirement to which the source would otherwise be subject. Such terms and conditions include federally-enforceable emissions caps assumed to avoid classification as a modification under any provision of Title I and alternative emissions limits approved pursuant to regulations promulgated under § 112(i)(5) of the Act;

v. Is not a modification under any provision of Title I of the Act. (Includes NSPS and NESHAP modifications, or a significant increase in emissions at PSD major sources; emission increases must be below PSD levels of significance.)

vi. The emergency generator shall use pipeline grade natural gas or other gaseous fuel that is compliant with NSPS Subpart Ja or diesel fuel that is compliant with NSPS Subpart IIII.

vii. The owner/operator shall comply with all applicable requirements of the New Source Performance Standards (NSPS), Subpart IIII, Stationary Compression Ignition (CI) Internal combustion Engines (ICE), for each affected facility including but not limited to: [40 CFR Part 60, Subpart IIII]

A. §60.4200 Am I subject to this subpart?

B. §60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI ICE?

C. §60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI ICE?

D. §60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI ICE subject to this subpart?

E. §60.4208 What is the deadline for importing and installing stationary CI ICE produced in the previous model year?

F. §60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI ICE?

G. §60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI ICE?

H. §60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI ICE with a displacement of less than 30 liters per cylinder?

I. §60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

J. §60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI ICE?

K. §60.4218 What parts of the General Provisions apply to me?

L. §60.4219 What definitions apply to this subpart?

viii. The owner/operator shall comply with all applicable requirements of the New Source Performance Standards (NSPS), Subpart JJJJ, Stationary Spark Ignition (SI) Internal

combustion Engines (ICE), for each affected facility including but not limited to: [40 CFR Part 60, Subpart JJJJ]

A. §60.4230 Am I subject to this subpart?

B. §60.4233 What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?

C. §60.4234 How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?

D. §60.4236 What is the deadline for importing or installing stationary SI ICE produced in the previous model year?

E. §60.4237 What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine?

F. §60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?

G. §60.4244 What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?

H. §60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

I. §60.4246 What parts of the General Provisions apply to me?

J. §60.4248 What definitions apply to this subpart?

ix. The owner/operator shall comply with all applicable requirements of the National Emission Standards For Hazardous Air Pollutants (NESHAP), Subpart ZZZZ, Stationary Reciprocating Internal Combustion Engines (RICE), for each affected facility including but not limited to: [40 CFR Part 63, Subpart ZZZZ]

A. §63.6580 What is the purpose of subpart ZZZZ?

B. §63.6585 Am I subject to this subpart?

C. §63.6590 What parts of my plant does this subpart cover?

D. §63.6595 When do I have to comply with this subpart?

E. §63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

F. §63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

G. §63.6602 What emission limitations must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

H. §63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

I. §63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?

J. §63.6605 What are my general requirements for complying with this subpart?

K. §63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

L. §63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

M. §63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE located at an area source of HAP emissions?

N. §63.6615 When must I conduct subsequent performance tests?

O. §63.6620 What performance tests and other procedures must I use?

P. §63.6625 What are my monitoring, installation, operation, and maintenance requirements?

Q. §63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

R. §63.6635 How do I monitor and collect data to demonstrate continuous compliance?

S. §63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

T. §63.6645What notifications must I submit and when?

U. §63.6650 What reports must I submit and when?

V. §63.6655 What records must I keep?

W. §63.6660 In what form and how long must I keep my records?

X. §63.6665 What parts of the General Provisions apply to me?

Y. §63.6670 Who implements and enforces this subpart?

Z. §63.6675 What definitions apply to this subpart?

x. The permittee shall notify AQD in writing not later than 7 days prior to start-up of the emergency generator. Said notice shall identify the make, model, horsepower, and manufacturer's emissions data in g/hp-hr for NOx, CO, VOC, and formaldehyde. The notice shall also indicate federal rule applicability, including but not limited to 40 CFR Part 60, Subpart IIII and JJJJ, and 40 CFR Part 63 Subpart ZZZZ.

c. At least once per calendar quarter, the permittee shall conduct tests of NO_X and CO emissions from the engine(s) and from any replacement engine/turbine when operating under representative conditions for that period. Testing is required for any engine/turbine subject to emission limits that runs for more than 220 hours during that calendar quarter. A quarterly test may be conducted no sooner than 20 calendar days after the most recent test. Testing shall be conducted using a portable analyzer in accordance with a protocol meeting the requirements of the latest AQD Portable Analyzer Guidance document, or an equivalent method approved by Air Quality. When four consecutive quarterly tests show the engine/turbine to be in compliance with the emissions limitations shown in the permit, then the testing frequency may be reduced to semi-annual testing. A semi-annual test may be conducted no sooner than 60 calendar days nor later than 180 calendar days after the most recent test. Likewise, when the following two consecutive semi-annual tests show compliance, the testing frequency may be reduced to annual testing. An annual test may be conducted no sooner than 120 calendar days nor later than 365 calendar days after the most recent test. Upon any showing of non-compliance with emissions limitations or testing that indicates that emissions are within 10% of the emission limitations, the testing frequency shall revert to quarterly. Reduced testing frequency does not apply to engines with catalytic converters. Any reduction in the testing frequency shall be noted in the next required compliance certification. [OAC 252:100-8-6(a)(3)(A)

d. A make, model number, and serial number or another acceptable form of permanent (non-removable) identification shall be on each engine. [OAC 252:100-43]

e. For engine(s) subject to emission limits: Maintain records of operating hours if less than 220 hours per quarter and not tested. [OAC 252:100-43]

EUG ENG-1a: Existing 2SLB Engines >500-hp "Subject" to 40 CFR Part 63 Subpart ZZZZ but With No Emission Limitations or Operating Requirements

EU ID	Point ID	Equipment	Horse Power (1)	Construction/ Modification Date
E-0068	E-0068	Sat Gas Unit engine	550	1950's
E-0072	E-0072	Sat Gas Unit engine	600	1941

1. Horsepower is shown for the purposes of regulatory applicability only and is not to be construed as a limit.

a. §63.6645 Notifications. Per §63.6590(b), new or reconstructed emergency RICE do not have to meet the requirements of RICE MACT except for the initial notification requirements.

b. These units are grandfathered (constructed prior to any applicable rule) internal combustion engines. These units are limited to the existing equipment as they are.

EUG ENG-1b: Existing Emergency Engines >500-hp "Subject" to 40 CFR Part 63 Subpart ZZZZ but With No Emission Limitations or Operating Requirements

EU ID	Point ID	Equipment	Horse Power (1)	Construction/ Modification Date
ENG-GFMPB	ENG-GFMPB	Park Bldg Generator Engine [CI, Emergency]	732	2004

1. Horsepower is shown for the purposes of regulatory applicability only and is not to be construed as a limit.

a. For EUG ENG-1b, the permittee shall comply with all applicable requirements of 40 CFR Part 63 Subpart ZZZZ including, but not limited to, the following:

[40 CFR Part 63 Subpart ZZZZ]

i. §63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

b. Reserved.

c. There are no emission limits applied to the EUG-ENG-1b units under Title V.

EUG ENG-2: CI Emergency Engines 500-hp or Less Subject to 40 CFR Part 63 Subpart ZZZZ Table 2c Requirements

EU ID	Point ID	Equipment	Horse Power (1)	Construction/ Modification Date
E-0003	E-0003	North Plant Fire Water Pump Engine	482	12/8/04
E-0004	E-0004	North Plant Fire Water Pump Engine	482	11/24/04
E-0061	E-0061	East Plant Fire Water Pump Engine	375	10/20/93
E-0062	E-0062	East Plant Fire Water Pump Engine	375	11/16/93
E-0158	Permanently removed from service by August 31, 2018, and shall not be returned to service			
E-ALKY	E-ALKY	HF Alky Backup Power Generator Engine	58	[Prior to 7/11/05]
E-GFMCB	E-GFMCB	Continental Building Backup Power Generator Engine	207	[Prior to 7/11/05]
E-GFMSB	E-GFMSB	Security Building Backup Power Generator Engine	207	6/30/03
E-GFMST	E-GFMST	South Tower Backup Power	150	[Prior to 7/11/05]

1. Horsepower is shown for the purposes of regulatory applicability only and is not to be construed as a limit.

a. For EUG ENG-2**,** the permittee shall comply with all applicable requirements of 40 CFR Part 63 Subpart ZZZZ including, but not limited to, the following:

[40 CFR Part 63 Subpart ZZZZ]

i. §63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c [of Subpart ZZZZ] which apply to you.

For each	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first.[2]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period

	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]

1. If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of Subpart ZZZZ, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.
2. Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.
3. Sources can petition the Administrator pursuant to the requirements of 40 CFR §63.6(g) for alternative work practices.

b. There are no emission limits applied to the EUG ENG-2 units under Title V.

EUG ENG-3: 4SLB Non-Emergency Engines <100-hp Subject to 40 CFR Part 63 Subpart *ZZZZ* Table 2c Requirements

EU ID	Point ID	Equipment	Horse Power (1)	Construction/ Modification Date
E-0075	E-0075	Gasoline Knock Test Engine	4	1969
E-0104	E-0104		4	1975
E-0106	E-0106		4	1975
E-LABB	E-LABB		4	1972

1. Horsepower is shown for the purposes of regulatory applicability only and is not to be construed as a limit.

a. For EUG ENG-3, the permittee shall comply with all applicable requirements of 40 CFR Part 63 Subpart ZZZZ including, but not limited to, the following:

[40 CFR Part 63 Subpart ZZZZ]

i. §63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c [of Subpart ZZZZ] which apply to you.

For each	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil filter every 1,440 hours of operation or annually, whichever comes first;[2] b. inspect spark plugs every 1,440 hours of operation annually, whichever comes first, and replace as necessary; c. inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]

2. Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of Subpart ZZZZ.
3. Sources can petition the Administrator pursuant to the requirements of 40 CFR §63.6(g) for alternative work practices.

b. There are no emission limits applied to the EUG ENG-3 units under Title V.

EUG ENG-4: Emergency CI Engines Subject to 40 CFR Part 60 Subpart IIII

EU ID	Point ID	Equipment	Horse Power (1)	Displace-ment (L/cylinder) (1)	Const./ Mod. Date	Pollutant	Emission Rate Limit g/hp-hr
ENG-GFMMB	ENG-GFMMB	Microwave Bldg Generator Engine for Emergency Backup Power	135	<10	Mfr'd 9/06 / Ordered Post-7/11/05	NO_X	6.9
ENG-E5017	ENG-E5017	SP Firewater Pump Engine	484	<30	Mfr'd 2007 / Ordered Post 7/11/05	NMHC(2) + NO_X	7.8
						CO	2.6
						PM	0.40
ENG-E5018	ENG-E5018	SP Firewater Pump Engine	484	<30	Mfr'd 2007 / Ordered Post 7/11/05	NMHC(2) + NO_X	7.8
						CO	2.6
						PM	0.40
ENG-EPIAB	ENG-EPIAB	East Plant Instrument Air Backup Compressor Engine	200	<30	4/20/11	NMHC(2) + NO_X	3.0
						CO	2.6
						PM	0.15
E-0118	E-0118	West Plant Fire Water Pump Engine	600	<10	8/03/17	NMHC(2) + NO_X	3.0
						PM	0.15

EU ID	Point ID	Equipment	Horse Power (1)	Displace-ment (L/cylinder) (1)	Const./ Mod. Date	Pollutant	Emission Rate Limit g/hp-hr
E-SPIAB	E-SPIAB	South Plant Backup Instrument Air Compressor Engine	575	<10	3/20/14	NMHC(2) + NO_X	3.0
						CO	2.6
						PM	0.15
E-37	E-37	Research West Backup Power Generator Engine	755	<10	10/18	NMHC(2) + NO_X	3.0
						CO	2.6
						PM	0.15

1. Horsepower and displacement are shown for the purposes of regulatory applicability only and is not to be construed as a limit.
2. Non-methane hydrocarbons.

a. For the listed engines, the permittee shall comply with all applicable requirements of 40 CFR Part 60 Subpart IIII, including, but not limited to, the following:

[40 CFR Part 60 Subpart IIII]

i. §60.4200 Am I subject to this subpart?

ii. §60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

iii. §60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

iv. §60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion subject to this subpart?

v. §60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

vi. §60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

vii. §60.4214 What are my notification, reporting, and recordkeeping requirements if a am an owner or operator of a stationary CI internal combustion engine?

EUG ENG-5: Non-Emergency CI Engines Subject to 40 CFR Part 60 Subpart IIII

EU ID	Point ID	Equipment	Horse Power (1)	Displace-ment (L/cylinder) (1)	Const./ Mod. Date	Pollutant	Emission Rate Limit g/hp-hr
ENG-4FCCAB	ENG-4FCCAB	FCC Air Blower Supplemental	140	<10	5/4/11	NMHC + NO_X	3.0
						CO	3.7
						PM	0.2
ENG-4FCCCAT	ENG-4FCCCAT	FCC Catalyst Loading	140	<10	6/14/11	NMHC + NO_X	3.0
						CO	3.7
						PM	0.2

1. Horsepower and displacement are shown for the purposes of regulatory applicability only and are not to be construed as a limit.

a. For the listed engines, the permittee shall comply with all applicable requirements of 40 CFR Part 60 Subpart IIII, including, but not limited to, the following:

[40 CFR Part 60 Subpart IIII]

i. §60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine? As listed in the above table.

ii. §60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

iii. §60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion subject to this subpart?

iv. §60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

v. §60.4214 Notification, What are my notification, reporting, and recordkeeping requirements if a am an owner or operator of a stationary CI internal combustion engine? Initial notification is not required for engines listed in the above table.

EUG FCC-1: Fluid Catalytic Cracking Unit Catalyst Regenerators Subject to 40 CFR Part 60 Subpart J and 40 CFR Part 63 Subpart UUU (Refinery MACT II)

EU ID	Point ID	Const / Mod Date	Pollutant	ppmvd Limit	Emission Limit (1)	
					lb/hr	TPY
No. 5 FCCU	No. 5 FCCU	1952 / 1972 (SC 35 mod) / 2023	NO_X	76.9 (2)(3)/ 37.1 (4)(5)	26.4	116
			SO_2	50 (2)(3)/ 25 (4)(5)	58.7/ 425 (10)	257
			VOC	-	-	-
			PM_{10}	-	30.0	131

1. 365-day rolling average, except as noted.
2. ppmdv @ 0% oxygen, 7-day rolling average.
3. Applies at all times of operation except that emission data during startup and shutdown of the No. 5 FCCU and/or the waste heat boiler will not be used in determining compliance with the short-term emission limits provided that during such periods the permittee implements good air pollution control practices to minimize emissions.
4. ppmdv @ 0% oxygen, 365-day rolling average.
5. Applies at all times of operation including during startup, shutdown, and malfunction of the No. 5 FCCU and/or the waste heat boiler and corresponding control equipment.
6. Reserved.
7. Reserved.
8. Reserved.
9. Reserved
10. Daily average from midnight to midnight.
11. Reserved.

a. Reserved.

b. Reserved.

c. Reserved.

d. Reserved.

e. For the No. 5 FCCU, the permittee shall comply with a PM emission limit of 0.9 lb per 1,000 lb coke burned. Compliance with this limit shall be demonstrated by a stack test using Method 5B and Method 202 conducted by no later than December 31, 2007.

f. The permittee shall install and maintain continuous emission monitoring systems (CEMS) for measuring NO_X and SO_2. The permittee shall certify, calibrate, maintain, and operate the NO_X and SO_2 CEMS in accordance with the requirements of 40 CFR §60.11, §60.13, and Part 60 Appendix A, B, and F. With respect to 40 CFR Part 60 Appendix F, in lieu of the requirements of 40 CFR Appendix F sections 5.1.1, 5.1.3, and 5.1.4, the permittee shall conduct either a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) once every twelve calendar quarters, provided that a cylinder gas audit is conducted each calendar quarter.

g. During flow monitor downtime the permittee may calculate daily stack flow based on air blower rate measurements and use this data with CEMS data or alternative monitoring data to determine compliance with mass emission rate limits in the table above. Records of emission and flow calculations shall be maintained when this option is used.
[OAC 252:100-43]

h. The No. 5 FCCU is subject to the standards of 40 CFR Part 60 Subpart J. The permittee shall comply with all applicable requirements for SO_2, PM, and opacity including, but not limited to, the following: [40 CFR Part 60, Subpart J]

i. §60.102 Standard for particulate matter.

ii. Reserved.

iii. §60.104 Standard for sulfur dioxide.

iv. §60.105 Monitoring of emissions and operations.

v. §60.106 Test methods and procedures. Compliance of the No. 5 FCCU with the PM emission limit of 1 pound per 1,000 pounds of coke burned shall be demonstrated by a stack test and measured using EPA Method 5B. The first stack test shall be conducted by no later than March 31, 2007, and subsequent annual stack tests shall be conducted by December 31st of the associated year through 2018. In accordance with "Revised Alternative monitoring Plan (AMP) – New Source Performance Standards (NSPS) for Petroleum Refineries (40 CFR Part 60 Subparts J and Ja) and National Emission Standards for Hazardous Air Pollutants (NESHAP for Petroleum Refineries (40 CFR Part 63 Subpart UUU) – Parametric Monitoring in Lieu of Continuous Opacity Monitoring System for Fluidized Catalytic Cracking Units (FCCUs) Wet Gas Scrubber (WGS) at the Phillips 66 Company-Ponca City Refinery, Ponca City, Oklahoma", subsequent (i.e., post-2018) performance tests shall be conducted at least once every five years to verify that the established operating parameter limits (OLPs) continue to be representative of facility operations and wet gas scrubber (WGS) performance, or to determine new representative values. A copy of each performance test report shall be submitted to EPA and the permitting authority along with any changes to the prior OLP values resulting from the data obtained during testing of the No. 5 FCCU WGS.

vi. §60.107 Reporting and recordkeeping requirements.

vii. §60.108 Performance test and compliance provisions.

i. The No. 5 FCCU is subject to 40 CFR Part 63 Subpart UUU. The permittee shall comply with all applicable requirements including, but not limited to, the following:

[40 CFR Part 63 Subpart UUU]

i. §63.1564 Standard for metal HAP. The No. 5 FCCU shall comply with the metal HAP requirements in this section by demonstrating compliance with the opacity standard in 40 CFR §60.102.

ii. §63.1565 Standard for organic HAP. The No. 5 FCCU shall comply with the organic HAP requirements in this section by demonstrating compliance with the CO standard in 40 CFR §60.103.

A. In accordance with the compliance extension granted by the Oklahoma Department of Environmental Quality letter dated May 31, 2017, the No. 5 FCCU shall comply with the following requirements by October 2, 2018.

I. 40 CFR §63.1565(a)(5)(ii), and

II. 40 CFR Table 41 To Subpart UUU of Part 63—Requirements For Installation, Operation, And Maintenance of Continuous Parameter Monitoring Systems.

iii. §63.1569 Bypass line requirements.

iv. §63.1570 General requirements.

v. §63.1571 Test methods and procedures. Compliance of the No. 5 FCCU with the PM emission requirements and limits of 40 CFR Part 63, Subpart UUU shall be in accordance with "Revised Alternative monitoring Plan (AMP) – New Source Performance Standards (NSPS) for Petroleum Refineries (40 CFR Part 60 Subparts J and Ja) and National Emission Standards for Hazardous Air Pollutants (NESHAP for Petroleum Refineries (40 CFR Part 63 Subpart UUU) – Parametric Monitoring in Lieu of Continuous Opacity Monitoring System for Fluidized Catalytic Cracking Units (FCCUs) Wet Gas Scrubber (WGS) at the Phillips 66 Company-Ponca City Refinery, Ponca City, Oklahoma". Performance tests shall be conducted at least once every five years to verify that the established operating parameter limits (OPLs) continue to be representative of facility operations and wet gas scrubber (WGS) performance, or to determine new representative values. A copy of each performance test report shall be submitted to EPA and the permitting authority along with any changes to the prior OPL values resulting from the data obtained during testing of the No. 5 FCCU WGS.

vi. §63.1572 Monitoring, installation, operation and maintenance requirements.

vii. §63.1574 Notifications.

viii. §63.1575 Reporting requirements.

ix. §63.1576 Recordkeeping requirements.

EUG FCC-2: Fluid Catalytic Cracking Unit Catalyst Regenerators Subject to 40 CFR Part 60 Subpart Ja and 40 CFR Part 63 Subpart UUU (Refinery MACT II)

EU ID	Point ID	Const / Mod Date	Pollutant	ppmvd Limit	Emission Limit (1)	
					lb/hr	TPY
No. 4 FCCU	No. 4 FCCU	1951 / 2021	NO_X	80(3)(4)	19.9	87
			CO	500(5) / 150(7)(8)	25.1	110(8)
			SO_2	50(3)(4) / 25(7)(8)	12.6	55
			VOC	-	1.9	8.3
			PM_{10}	-	16.7(9)	73(9) 110(10)
No. 5 FCCU	No. 5 FCCU	1952 / 1972 (SC 35 mod) / 2023	CO	500(5) / 150 (7)(8)	47.2	206.7(6)

1. 365-day rolling average, except as noted.
2. Reserved.
3. ppmdv @ 0% oxygen, 7-day rolling average.
4. Applies at all times of operation except that emission data during startup and shutdown of the No. 4 FCCU will not be used in determining compliance with the short-term emission limits provided that during such periods the permittee implements good air pollution control practices to minimize emissions.
5. ppmdv @ 0 % oxygen, 1-hr average (NSPS Subpart Ja).
6. Corresponds to 150 ppmvd @ 0% oxygen, 365-day rolling average.
7. ppmdv @ 0% oxygen, 365-day rolling average.
8. Applies at all time of operation including startup, shutdown, and malfunction of the No. 4 FCCU and No. 5 FCCU and the corresponding control equipment.
9. Non-sulfate PM. Measured using EPA Method 5B.
10. Total PM. Measured using EPA Method 5B and EPA Method 202 or alternative.

a. During flow monitor downtime the permittee may calculate daily stack flow based on air blower rate measurements and use this data with CEMS data or alternative monitoring data to determine compliance with mass emission rate limits in the table above. Records of emission and flow calculations shall be maintained when this option is used.

[OAC 252:100-43]

b. The No. 4 FCCU and CO emissions from the No. 5 FCCU are subject to the standards of 40 CFR Part 60 Subpart Ja. The permittee shall comply with all applicable requirements including, but not limited to, the following: [40 CFR Part 60, Subpart Ja]

i. §60.100a Applicability, designation of affected facility, and reconstruction.

ii. §60.101a Definitions.

iii. §60.102a Emission limitations.

A. §60.102a(b)(1)(i) – Particulate Matter (PM): 1 pound per 1,000 pounds coke burn-off.

B. §60.102a(b)(2) – Nitrogen Oxides (NO_X): 80 parts per million by volume (ppmv), dry basis corrected to 0 percent excess air, on a 7-day rolling average basis.

C. §60.102a(b)(3) – Sulfur Dioxide (SO_2): 50 ppmv, dry basis corrected to 0 percent excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 percent excess air, on a 365-day rolling average basis.

D. §60.102a(b)(4) – Carbon Monoxide (CO): 500 ppmv, dry basis corrected to 0 percent excess air, on an hourly average basis.

E. §60.102a(c)(2) – FCCU controlled using a wet scrubber.

iv. §60.104a Performance tests.

v. §60.105a Monitoring of emissions and operations for fluid catalytic cracking units (FCCU) and fluid coking units (FCU).

vi. §60.108a Recordkeeping and reporting requirements.

vii. §60.109a Delegation of authority.

c. The No. 4 FCCU and CO emissions from the No. 5 FCCU are subject to 40 CFR Part 63 Subpart UUU. The permittee shall comply with all applicable requirements including, but not limited to, the following: [40 CFR Part 63 Subpart UUU]

i. §63.1564 What are my requirements for metal HAP emissions from catalytic cracking units?

A. Compliance of the No. 4 FCCU with the metal HAP requirements in this section shall be met by demonstrating compliance with the particulate matter (PM) emission limitations and requirements for NSPS units.

ii. §63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?

A. Compliance for the No. 4 FCCU and the No. 5 FCCU with the organic HAP requirements in this section shall be met by demonstrating compliance with the carbon monoxide (CO) emission limitations and requirements for NSPS units.

iii. §§63.1570 through 63.1573 General Compliance Requirements

iv. §§63.1574 through 63.1576 Notifications, reports, and recordkeeping.

v. §§63.1577 through 63.1579 Other requirements and information.

d. For the No. 4 FCCU and the No. 5 FCCU during periods of startup, shutdown, and hot standby, the oxygen (O_2) concentration in the exhaust gas from your catalyst regenerator shall be maintained at or above 1 volume percent (dry basis) or 1 volume percent (wet basis with no moisture correction).

e. For the No. 5 FCCU, the permittee shall comply with a PM emission limit of 0.9 lb per 1,000 lb coke burned. Compliance with this limit shall be demonstrated by a stack test using Method 5B and Method 202 conducted by no later than December 31, 2007.

EUG CRU-1: Catalytic Reforming Unit Catalyst Regenerator Vents Subject to 40 CFR Part 63 Subpart UUU (Refinery MACT II)

EU ID	Point ID	Equipment	Construction/ Modification Date
No. 2 CRU	No. 2 CRU	No. 2 Catalytic Reforming Unit Catalyst Regenerator Vent	1957
No. 3 CRU	No. 3 CRU	No. 3 Catalytic Reforming Unit Catalyst Regenerator Vent	1956

a. The listed equipment is subject to the standards of 40 CFR Part 63 Subpart UUU. The permittee shall comply with all applicable requirements including, but not limited to, the following: [40 CFR Part 63 Subpart UUU]

i. §63.1566 Standard for organic HAPs.

ii. §63.1567 Standard for inorganic HAPs.

iii. §63.1569 Bypass line requirements.

iv. §63.1570 General requirements.

v. §63.1571 Test methods and procedures.

vi. §63.1572 Monitoring, installation, operation and maintenance requirements.

vii. §63.1574 Notifications.

viii. §63.1575 Reporting requirements.

ix. §63.1576 Recordkeeping requirements.

EUG FLR-1: Flares Subject to 40 CFR Part 60 Subpart Ja

EU ID	Point ID	Equipment	Construction/ Modification Date
Flare-CC	Flare-CC	Coker/Combo Alky Flare	1970
Flare-CF	Flare-CF	Clean Fuels and West Plant Flare	2003
Flare-EP	Flare-EP	East Plant Flare	1990
Flare-SP	Flare-SP	South Plant Flare	1972
Flare-Temp	Flare-Temp	Temporary Flare	1994

a. Each of the listed flares is subject to the provisions of 40 CFR Part 60 Subpart Ja and shall comply with all applicable requirements for flares, contained in Subpart Ja with the exception of §§60.103a(c-e, h) and 60.107a(a)(2). Beginning November 11, 2015, each flare shall comply with all applicable requirements including, but not limited to, the following: [40 CFR Part 60, Subpart Ja]

   i. §60.100a Applicability, designation of affected facility, and reconstruction

   ii. §60.101a Definitions

   iii. §60.102a Emissions limitations

   iv. §60.103a Design, equipment, work practice or operational standards

   v. §60.104a Performance tests

   vi. §60.107a Monitoring of emissions and operations for fuel gas combustion devices and flares

   vii. §60.108a Reporting and recordkeeping requirements

   viii. §60.109a Delegation of authority

b. On or before January 30, 2019, the owner or operator of a flare used as a control device for an emission point subject to 40 CFR Part 63, Subpart CC shall comply with all applicable requirements including, but not limited to, the following: [40 CFR Part 63, Subpart CC]

   i. §63.640 Applicability and designation of affected source;

   ii. §63.642 General standards;

   iii. §63.655 Reporting and recordkeeping requirements;

   iv. §63.670 Requirements for flare control devices; and

A. Develop a flare management plan to minimize flaring during periods of startup, shutdown, or emergency releases.

v. §63.671 Requirements for flare monitoring systems.

c. For the purpose of demonstrating compliance with §63.670(h), the permittee shall not be required to retain records longer than three (3) years as required by §63.655(i)(9)(ii), and shall be exempt from the five (5) year record retention requirement of OAC 252:100-8-6(a)(3)(B)(ii). [40 CFR Part 63, Subpart CC]

EUG LOD-1: Reserved

EUG LOD-2: Loading Racks Subject to Oklahoma Rules or Permit Requirements

EU ID	Point ID	Process	Const/ Mod Date	Throughput Limit (gallons)	VOC Emissions Limit (2)	
					lb/hr	TPY
Load-SP	Load-SP	South Plant Loading Rack (Distillates)	Est. 1930's	175,200,000 (1)	3.0	8.8

1. Calendar year total.
2. Calendar year total. Compliance with the throughput limit demonstrates compliance with the VOC emissions limit.

a. When loading more than 40,000 gallons per day of products with a vapor pressure of 1.5 psia or more under actual storage conditions, all tank trucks or trailers must be bottom loaded with hatches closed or be equipped with a vapor collection and disposal system that meets the specification of OAC 252:100-37-16(a)(1). A means shall be provided to prevent VOC drainage from the loading device when it is removed from any tank truck or trailer, or to accomplish complete drainage before removal. [OAC 252:100-37-16(a)]

b. When the Load-SP is operated to load distillates, the permittee shall maintain records of daily and cumulative annual throughput for distillate loaded. [OAC 252:100-43]

EUG LOD-3: Insignificant Activity Loading Racks

There are no emissions limitations for these loading racks.

EU ID	Point ID	Equipment	Insignificant Activity Reason
Load-Refuel#1	Load-Refuel#1	Refinery Vehicle Refueling	App. I: Miscellaneous - < 5 TPY
Load-Refuel#2	Load-Refuel#2	Motor Pool Refueling	App. I: Miscellaneous - < 5 TPY
Load-SF	Load-SF	Santa Fe Loading Rack (Distillates)	App. I: Miscellaneous - < 5 TPY

EU ID	Point ID	Equipment	Insignificant Activity Reason
Load-Resid	Load-Resid	Resid Truck Loading Rack	App. I: Miscellaneous - < 5 TPY

EUG VNT-1: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 1 Miscellaneous Process Vents

There are no emissions limitations for these miscellaneous process vents.

EU ID	Point ID	Equipment	Construction/ Modification Date
VNT-D0749	Flare-CC	D-749 Merox disulfide separator drum	2001

a. The listed miscellaneous process vents are subject to 40 CFR Part 63 Subpart CC. The permittee shall comply with all applicable requirements including, but not limited to, the following: [40 CFR Part 63 Subpart CC]

i. §63.642 General Standards

ii. §63.643 Miscellaneous process vent provisions

iii. §63.644 Monitoring provisions for miscellaneous process vents

iv. §63.645 Test methods and procedures for miscellaneous process vents

v. §63.654 Reporting and recordkeeping requirements

EUG VNT-2: 40 CFR Part 63 Subpart CC (Refinery MACT I) Group 2 Miscellaneous Process Vents

There are no emissions limitations for these miscellaneous process vents.

EU ID	Point ID	Equipment	Construction/ Modification Date
VNT-D0701	VNT-D0701	D-701 vent/drain	1970
VNT-D0702	VNT-D0702	D-702 vent/drain	1970
VNT-D0704	VNT-D0704	D-704 vent/drain	1970
VNT-D0714	VNT-D0714	D-714 vent/drain	1970
VNT-D0717	Flare-CC	D-717 deprop overhead reflux	1997
VNT-D0741	Flare-CC	D-741 ASO/KOH separator	1985
VNT-D0748	Flare-CC	D-748 fuel gas drum	1971
VNT-D5173	VNT-D5173	D-5173 vent/drain	1944
VNT-Load SF LPG	VNT-Load SF	Loading vent line purge to atmosphere	Est. 1930's

EU ID	Point ID	Equipment	Construction/ Modification Date
VNT-Load SF Toluene	VNT-Load SF Toluene	Toluene unloading vent to atmosphere	Est. 1930's
VNT-Load SP LPG	VNT-Load SP	Loading and vent line purge to atmosphere	1997
VNT-T0256	Flare-CC	Alky flare slop tank vent	1932
VNT-W0193	Flare-CC	W-193 overhead non-condensables	1970
VNT-D0452	VNT-D0452	D-452 vent/drain	1990

a. The listed miscellaneous process vents are subject only to the applicable reporting requirements of 40 CFR Part 63 Subpart CC. The permittee shall comply with the reporting requirements for Group 2 miscellaneous process vents in 40 CFR §63.654(f).
[40 CFR Part 63 Subpart CC]

EUG VNT-3: Reserved

EUG VNT-4: 40 CFR Part 63 Subpart GGGGG (Site Remediation MACT) Process Vents

EU ID	Point ID	Equipment	Construction/ Modification Date
VNT-SVE	VNT-SVE	Soil Vapor Extraction (SVE) System Vent	1998

a. In accordance with the exemption provided under 40 CFR Part 63 Subpart GGGGG [40 CFR §63.7881(c)], process vent VNT-SVE is not subject to the requirements of 40 CFR Part 63 Subpart GGGGG except for the recordkeeping requirements specified in 40 CFR §63.7881(c). Whenever the exemption under 40 CFR §63.7881(c) does not apply, the permittee shall comply with all applicable requirements including, but not limited to, the following: [40 CFR Part 63 Subpart GGGGG]

i. §63.7884 – 7885 General standards.

ii. §§63.7890 – 63.7893 Standards for process vents.

iii. §§63.7935, 63.7937 and 63.7938 General compliance requirements.

iv. §§63.7940 – 63.7944 Performance tests.

v. §§63.7950 – 63.7953 Notifications, reports and records.

vi. §§63.7955 – 63.7957 Other requirements and information.

EUG VNT-5: Insignificant Activity Atmospheric Process Vents

There are no emissions limitations for these atmospheric process vents.

EU ID	Point ID	Equipment	Insignificant Activity Reason
VNT-C0024	VNT-C0024	No. 5 HDT Hydrogen Compressor Distance Piece Vent	App. I: Miscellaneous - < 5 TPY
VNT-C0060	VNT-C0060	No. 7 HDT Compressor Distance Piece Vent	App. I: Miscellaneous – < 5 TPY
VNT-C0061	VNT-C0061	No. 7 HDT Compressor Distance Piece Vent	App. I: Miscellaneous – < 5 TPY
VNT-C0125	VNT-C0125	No. 3HDS Compressor Distance Piece Vent	App. I: Miscellaneous – < 5 TPY
VNT-C5037	VNT-C5037	Butamer Hydrogen Compressor Distance Piece Vent	App. I: Miscellaneous – < 5 TPY
VNT-D0809	VNT-D0809	Hydrogen Makeup Vent	App. I: Miscellaneous – < 5 TPY
VNT-D8806	VNT-D8806	No. 1 Hydrogen Plant Deaerator Vent	App. I: Miscellaneous – < 5 TPY

EUG VNT-6: Equipment Subject to the Maintenance Vent Provisions of 40 CFR Part 63, Subpart CC (Refinery MACT I)

a. Equipment subject to the following under 40 CFR Part 63 will comply with the applicable requirements by January 30, 2019. [40 CFR Part 63, Subpart CC]

   i. 40 CFR Part 63, §63.643(c),

   ii. §63.655(g)(13), and

   iii. §63.655(i)(12).

FUGITIVE EMISSION EQUIPMENT

Note: equipment counts are estimates only for the purposes of documenting regulatory applicability and are not to be construed as operating limitations.

EUG FUG-1: Fugitive Piping Equipment Leaks Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) and/or 40 CFR Part 60 Subpart GGGa

EU ID	Point ID	Equipment LL = Light Liquid HL = Heavy Liquid	Number of Items	Construction/ Modification Date
Refinery-Wide Piping Equipment Fugitive Leaks	Refinery-Wide Piping Equipment Fugitive Leaks	Gas Valves	24,787	Various
		LL Valves	28,698	Various
		HL Valves	17,928	Various
		Connectors	241,302	Various
		LL Pump Seals	393	Various
		HL Pump Seals	427	Various
		Gas Compressors	20	Various
		Gas Relief Valves to Atm	14	Various
		Gas Relief Valves to Flare	509	Various
		Sample Stations	606	Various

a. Equipment counts for equipment leaks are included solely for the purpose of documenting regulatory applicability. The exact counts are not to be construed as operating limitations. The applicable requirements associated with fugitive emissions from equipment leaks are set forth in the equipment leak detection and repair (LDAR) program as specified in the Specific Conditions for this section. [40 CFR Part 63 Subparts CC and GGGa]

b. The listed equipment is subject to 40 CFR Part 60 Subpart GGGa. Subpart GGGa specifies compliance with certain requirements of 40 CFR Part 60 Subpart VVa. The permittee shall comply with all applicable requirements of Subpart GGGa including, but not limited to, the following: [40 CFR Part 63 Subpart GGGa]

i. §60.592a Standards.

A. An owner or operator shall comply with the requirements of 40 CFR §§60.482-1a to 60.482-10a.

B. As an alternative to the requirements of §60.482-7a, an owner or operator may elect to comply with the requirements of 40 CFR §§60.483-1a, 60.483-2a, or the Phase III provisions in 40 CFR §63.168, except a an owner or operator may elect to follow the provisions in 40 CFR §60.482-7a(f) for any valve that is designated as leakless.

C. Each owner or operator shall comply with the requirements of 40 CFR §60.485a except as provided in 40 CFR §60.493a.

D. Each owner or operator shall comply with the requirements of 40 CFR §§60.486a and 60.487a.

ii. §63.593a Exceptions

A. Connectors in gas/vapor or light liquid service are exempt from the requirements in 40 CFR §60.482-11a, provided the owner or operator complies with 40 CFR §60.482-8a for all connectors, not just those in heavy liquid service.

c. The listed equipment is subject to 40 CFR Part 63 Subpart CC. 40 CFR §63.640(p)(2) specifies that equipment leaks that are also subject to the provisions of 40 CFR Part 60 Subpart GGGa are required to comply only with the provisions specified in 40 CFR Part 60 Subpart GGGa.

EUG FUG-2: Fugitive Oily Water Sewer System Component Leaks Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I) and 40 CFR Part 61 Subpart FF (Benzene Waste Operations)

EU ID	Point ID	Equipment (WDB = water draw box)	Number of Items	Construction/ Modification Date
FUG-Coker ORU	FUG-CC	Process drains	27	1991
		Junction boxes/sumps/WDB	6	1991
FUG-1HP, 2HP, 2Isom, 8HDT, 9HDT, BFU & FGRU	FUG-CF	Process drains	147	Various
		Junction boxes/sumps/WDB	52	2003-2006
FUG-2CTU, 3CRU, 4FCC & ORU	FUG-EP	Process drains	177	Various
		Junction boxes/sumps/WDB	33	Various
FUG-1SWS	FUG-SP	Process drains	10	Various
		Junction boxes/sumps/WDB	1	Various
FUG-2SWS	FUG-SP	Process drains	11	2005
		Junction boxes/sumps/WDB	0	2005
FUG-WP ORU	FUG-WP	Process drains	19	1991
		Junction boxes/sumps/WDB	8	1991
FUG-OM Tank Farm & WWTS	FUG-OM	Process drains	0	n/a
		Junction boxes/sumps/WDB	27	Various
FUG-SP Tank Farm	FUG-SP	Process drains	0	n/a
		Junction boxes/sumps/WDB	3	Various
FUG-6HDT	FUG-CC	Process drains	13	1992
		Junction boxes/sumps/WDB	12	1992
FUG-TOP	FUG-WP	Process drains	4	2015
		Junction boxes/sumps/WDB	1	2015
FUG-DEC3	FUG-CC	Process drains	4	2017
		Junction boxes/sumps/WDB	1	2017

a. The listed equipment is subject to 40 CFR Part 63 Subpart CC. Listed equipment that was constructed, reconstructed, or modified after May 4, 1987 is also subject to 40 CFR Part 60 Subpart QQQ. The "overlap" provision of 40 CFR §63.640(o) states that a Group 1 wastewater stream managed in a piece of equipment that is also subject to the provisions of

Subpart QQQ is only required to comply with Subpart CC. The permittee shall comply with all applicable requirements for Subpart CC including, but not limited to, the following: [40 CFR Part 63 Subpart CC]

i. §63.642 General Standards.

ii. §63.647 Wastewater provisions. Each owner or operator of a Group 1 wastewater stream shall comply with the requirements of 40 CFR §§61.340 through 61.355 of 40 CFR Part 61 Subpart FF for each process wastewater stream that meets the definition in 40 CFR §63.641.

A. §61.342 General standards.

B. §61.346 Individual drain systems.

C. §61.350 Standards: Delay of repair.

D. §61.355 Test methods, procedures and compliance provisions.

iii. §63.654 Reporting and recordkeeping requirements.

b. The listed equipment is also subject to 40 CFR Part 61 Subpart FF. In addition to the requirements of 40 CFR Part 63, Subpart CC above, the permittee shall comply with the recordkeeping and reporting requirements of Subpart FF including, but not limited to, the following: [40 CFR Part 61 Subpart FF]

i. §61.356 Recordkeeping requirements.

ii. §61.357 Reporting requirements.

c. Flare-CC in EUG FLR-1 is a 40 CFR Part 61 Subpart FF control device. The permittee shall comply with all applicable requirements in Subpart FF including, but not limited to, the following: [40 CFR Part 61 Subpart FF]

i. §61.342 General standards.

ii. §61.349 Standards: Closed-vent systems and control devices

iii. §61.354 Monitoring of operations.

iv. §61.356 Recordkeeping requirements.

v. §61.357 Reporting requirements.

EUG FUG-3: Fugitive Oily Water Sewer System Component Leaks Subject to 40 CFR Part 60 Subpart QQQ

EU ID	Point ID	Equipment	Number of Items	Construction/ Modification Date
FUG-7HDT	FUG-WP	Process drains	29	1989
		Junction boxes/sumps/WDB	13	1989

a. The permittee shall demonstrate initially and once per year that the flow-weighted annual average benzene concentration in the waste stream(s) is less than 10 ppmw.
[40 CFR §61.342(c)(3)]

b. The listed equipment is subject to 40 CFR Part 60 Subpart QQQ and shall comply with all applicable requirements including, but not limited to, the following:
[40 CFR Part 60 Subpart QQQ]

i. §60.691 Definitions.

ii. §60.692-1 Standards: General.

iii. §60.692-2 Standards: Individual drain systems.

iv. §60.692-4 Standards: Aggregate facilities.

v. §60.692-6 Standards: Delay of repair.

vi. §60.692-7 Standards: Delay of compliance.

vii. §60.693-1 Standards: Alternative standards for individual drain systems.

viii. §60.696 Performance test methods and procedures and compliance provisions.

ix. §60.697 Recordkeeping requirements.

x. §60.698 Reporting requirements.

EUG FUG-4: Fugitive Oily Water Sewer System Component Leaks Subject to 40 CFR Part 61 Subpart FF (Benzene Waste Operations) Exemption Recordkeeping Requirements

EU ID	Point ID	Equipment	Number of Items	Construction/ Modification Date
Refinery-Wide Oily Water Sewer Component Fugitive Leaks	Refinery-Wide Oily Water Sewer Component Fugitive Leaks	Process drains (controlled)	78	Various
		Process drains (uncontrolled)	2,118	Various
		Junction boxes/sumps (controlled)	0	Various
		Closed Drains	243	Various
		Junction boxes/sumps (uncontrolled)	303	Various

a. The permittee shall maintain records that demonstrate initially and once per year that the flow-weighted annual average benzene concentration in the waste stream(s) is less than 10 ppmw. [40 CFR §61.342(c)(3)]

EUG FUG-6: Cooling Tower Fugitive Sources Subject to 40 CFR Part 63 Subpart CC (Refinery MACT I)

EU ID	Point ID	Equipment	Construction/ Modification Date
Y-0002	Y-0002	West Plant Marley EPHCC01 Cooling Tower	1953
Y-0002 A	Y-0002 A	West Plant Marley 6615302 Cooling Tower	1973
Y-0003	Y-0003	Coker Cooling Tower	1946
Y-0005	Y-0005	South Plant North & South Loop Cooling Tower	1943
Y-0006	Y-0006	Combo Cooling Tower	1956
Y-0007	Y-0007	Main Power Plant Cooling Tower	2010
Y-0010	Y-0010	Alky Cooling Tower	1971
Y-6026	Y-6026	East Plant Marley Cooling Tower	1953
Y-6027	Y-6027	East Plant Pritchard Cooling Tower	1956
Y-8000	Y-8000	Clean Gasoline Unit Cooling Tower	2003

1. Estimated project timing.

a. Y-8000 shall be constructed with drift eliminators and a flow monitor. [OAC 252:100-8-6(a)]

b. Reserved.

c. Y-0007 cooling tower shall be constructed with drift eliminators. [OAC 252:100-8-6(a)]

d. Reserved

e. Reserved

f. Each cooling tower is subject to and shall comply with the applicable sections of 40 CFR Part 63, Subpart CC, including, but not limited to: [40 CFR §§63.640-656]

i. §63.640 Applicability and Designation of Affected Source

ii. §63.641 Definitions

iii. §63.654 Heat Exchange Systems

iv. §63.655 Reporting and Recordkeeping Requirements

EUG FUG-6.1: Insignificant Cooling Tower Fugitive Sources

There are no emissions limitations for these cooling towers.

EU ID	Point ID	Equipment	Construction/ Modification Date	Insignificant Activity Reason
Y-0009	Y-0009	ASU Cooling Tower	1992	App. I: < 5 TPY (Actual)

EUG FUG-7: Materials Handling Fugitive Sources Subject to Oklahoma Rules or Permit Requirements

EU ID	Point ID	Process Rate Limit (Dry Tons/yr) (1)	PM_{10} Emissions Limit (2)	
			lb/hr	TPY
Coke Loading Facility	Coke Loading Facility	475,000	2.7	8.8

1. 12-month rolling total.
2. 12-month rolling total. Compliance with the process rate limit demonstrates compliance with the PM_{10} emissions limit.

a. The permittee shall take reasonable precautions to minimize fugitive dust emissions from the Coke Loading Facility loading and unloading operations, roads, and stockpiles. Water sprays shall be used for the minimization of fugitive dust as deemed necessary. [OAC 252:100-8-6(a)]

b. The permittee shall maintain monthly records of the 12-month rolling total dry petroleum coke, or wet petroleum coke assuming 10% moisture, shipped from the Coke Loading Facility. [OAC 252:100-43]

c. The permittee shall demonstrate compliance with the coke drum operations emissions limit by the most recent version of the Phillips 66 Company in-house coke drum operation emissions calculation tool. [OAC 252:100-43]

EUG FUG-8: Insignificant Activity Fugitive Sources

There is no emissions limitation for the application of biosludge.

EU ID	Point ID	Equipment	Insignificant Activity Reason
Landfarm	Landfarm	Application of ASU biosludge to landfarm	App. I: Fugitives – Land farms

EUG COK-1 Delayed Cokers Subject to 40 CFR Part 60 Subpart Ja and 40 CFR Part 63 Subpart CC

EU ID	Point ID	Pollutant	Emissions	
			lbs/hr(1)	TPY
No. 7 Coker unit	Coke Drum Operations	VOC	5.0	22.0
		$PM_{10/2.5}$	0.7	3.0
		H_2S	0.9	4.0

1. 12-month rolling total, except as otherwise specified in the specific conditions. Time period basis is midnight to midnight.

a. The No. 7 Coker Unit is subject to 40 CFR Part 60 Subpart Ja, and shall comply with any and all applicable requirements, including but not limited to: [40CFR Part 60 Subpart Ja]

i. §60.103a Work Practice Standards.

b. The No. 7 Coker Unit is subject to 40 CFR Part 63 Subpart CC, and shall comply with any and all applicable requirements, including but not limited to:
[40 CFR Part 63 Subpart CC]

i. §63.640 Applicability and Designation of Affected Source

ii. §63.641 Definitions

iii. §63.642 General Standards

iv. §63.655 Reporting and Recordkeeping Requirements

v. §63.657 Delayed Coking Unit Decoking Operation Standards

c. The permittee shall demonstrate compliance with the coke drum operations emission limit by the most recent version of the Phillips 66 Company in-house coke drum operations emissions calculation tool.

FACILITY-WIDE

EUG FW: Facility-Wide Applicable Requirements

There are no facility-wide emissions limitations.

Specific Conditions continued:

2. The following records shall be maintained on site to verify insignificant activities. [OAC 252:8-6(a)(3)(b)]

   a. Reserved.

   b. Reserved.

   c. True vapor pressure for tanks satisfying the criteria of capacity less than 39,894 gallons and storing a liquid with a vapor pressure less than 1.5 psia maximum.

   d. Potential to emit of activities having a PTE of no more than 5 TPY of any criteria pollutant.

3. Except where inconsistent with the "minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline" or any State of Oklahoma regulatory agency, no owner or operator shall allow VOC gases to be emitted from a vapor recovery blowdown system unless these gases are burned by a smokeless flare or equally effective control device as approved by the Division Director. This requirement does not apply to VOC's with a vapor pressure of less than 1.5 psia under actual storage conditions or to equipment installed on or prior to December 28, 1974. [OAC 252:100-37-4(a) & 252:100-37-35(b)]

4. Reserved.

5. Asbestos demolition, renovation, and disposal activities at the facility are subject to the applicable requirements of 40 CFR Part 61 Subpart M. The permittee shall comply with all applicable requirements of Subpart M including, but not limited to, the following: [40 CFR Part 61 Subpart M]

   a. §61.145 Standard for demolition and renovation.

   b. §61.146 Standard for insulating materials.

   c. §61.148 Standard for spraying.

   d. §61.150 Standard for waste disposal for manufacturing, fabricating, demolition, renovation, and spraying operations.

   e. §61.152 Air cleaning.

6. The permittee shall comply with the following requirements for handling asbestos: [OAC 252:100-41-16]

   a. Before being handled, stored or transported in or to the outside air, friable asbestos from demolition/renovation operations shall be double bagged in six-mil plastic bags, or single bagged in one six-mil plastic bag and placed in a disposable drum, or contained in any other manner approved in advance by the AQD Director.

   b. When demolition/renovation operations must take place in the outdoor air, friable asbestos removed in such operations shall be immediately bagged or contained in accordance with (a) above.

   c. Friable asbestos materials used on pipes or other outdoor structures shall not be allowed to weather or deteriorate and become exposed to, or dispersed in the outside air.

   d. Friable asbestos materials shall, in addition to other provisions concerning disposal, be disposed of in a facility approved for asbestos by the Solid Waste Management Division of DEQ.

7. The permittee is authorized to operate the facility continuously (24 hours per day, every day of the year). [OAC 252:100-8-6(a)]

8. The following applies to VOC storage vessels that meet the stated criteria:

   a. VOC storage vessels constructed after December 28, 1974 greater than 400 gallons in capacity and storing a liquid with a vapor pressure greater than 1.5 psia shall have a permanent submerged fill pipe or a vapor recovery system. VOC storage vessels that are subject to equipment standards (e.g. a fixed roof in combination with an internal floating cover, an external floating roof, or a closed vent system and control device) in 40 CFR Part 60 Subparts K, Ka or Kb are exempt from this requirement. [OAC 252:100-37-15(b) & (c)]

   b. VOC storage vessels constructed after December 28, 1974 greater than 40,000 gallons in capacity and storing a liquid with a vapor pressure greater than 1.5 psia shall be pressure vessels or shall be equipped with a vapor-loss control device as specified in OAC 252:100-37-15(a). VOC storage vessels that are subject to equipment standards (e.g. a fixed roof in combination with an internal floating cover, an external floating roof, or a closed vent system and control device) in 40 CFR Part 60 Subparts K, Ka or Kb are exempt from this requirement. [OAC 252:100-37-15(a) & (c)]

   c. Records of dimension, capacity, VOL stored, period of storage, and maximum true vapor pressure shall be kept for the following types of storage vessels:

i. VOL storage vessels constructed, reconstructed, or modified after July 23, 1984 with a capacity of at least 20,000 gallons but less than 40,000 gallons and storing a VOL with a maximum true vapor pressure of at least 2.2 psia.
[40 CFR §§60.116b(b) & (c)]

ii. VOL storage vessels constructed, reconstructed, or modified after July 23, 1984 with a capacity of 40,000 gallons or more and storing a VOL with a maximum true vapor pressure of at least 0.51 psia. [40 CFR §§60.116b(b) & (c)]

9. In accordance with the facility-wide exemption provided under 40 CFR Part 63 Subpart DD in 40 CFR §63.680(d), whenever the total annual HAP contained in the off-site material received is less than 1 Mg/year, the permittee shall only be required to maintain records of the initial determination of the amount of off-site HAP received and an updated record whenever the amount of off-site HAP received changes enough to possibly exceed the 1 Mg/year limitation. Whenever the facility-wide exemption under 40 CFR §63.680(d) does not apply, the permittee shall comply with all applicable standards, including but not limited to, the following:
[40 CFR Part 63 Subpart DD]

a. §63.683 Standards: General.

b. §63.684 Standards: Off-site material treatment.

c. §63.685 Standards: Tanks.

d. §63.686 Standards: Oil-water and organic-water separators.

e. §63.687 Standards: Surface impoundments.

f. §63.688 Standards: Canisters.

g. §63.689 Standards: Transfer systems.

h. §63.690 Standards: Process Vents.

i. §63.691 Standards: Equipment Leaks.

j. §63.693 Standards: Closed-vent systems and control devices.

k. §63.694 Test methods and procedures.

l. §63.695 Inspection and monitoring requirements.

m. §63.696 Recordkeeping requirements.

n. §63.697 Reporting requirements.

10. In accordance with the exemption provided under 40 CFR Part 63 Subpart GGGGG [40 CFR §63.7881(c)], site remediation is not subject to the requirements of 40 CFR Part 63 Subpart GGGGG except for the recordkeeping requirements specified in 40 CFR §63.7881(c),. Compliance requirements for the soil vapor extraction system vent are listed under the EUG for 40 CFR Part 63 Subpart GGGGG process vents. Whenever the exemption under 40 CFR §63.7881(c) does not apply, the permittee shall comply with all applicable requirements including, but not limited to, the following: [40 CFR Part 63 Subpart GGGGG]

    a. §63.7884-7887 General standards.

    b. §63.7890-63.7893 Standards for process vents.

    c. §63.7895-63.7898 Standards for tanks.

    d. §63.7900-63.7903 Standards for containers.

    e. §63.7905-63.7908 Standards for surface impoundments.

    f. §63.7910-63.7913 Standards for separators.

    g. §63.7915-63.7918 Standards for transfer systems.

    h. §63.7920-63.7922 Standards for equipment leaks.

    i. §63.7925-63.7928 Standards for closed vent systems and control devices.

    j. §63.7935-63.7938 General compliance requirements.

    k. §63.7940-63.7944 Performance tests.

    l. §63.7945-63.7947 Continuous monitoring systems.

    m. §63.7950-63.7953 Notifications, reports and records.

    n. §63.7955-63.7957 Other requirements and information.

11. 40 CFR Part 60 Subpart A applies to equipment subject to New Source Performance Standards under Part 60. Unless applicable subparts specify otherwise, the permittee shall comply with all applicable requirements of Subpart A, including but not limited to, the following:
[40 CFR Part 60 Subpart A]

    a. §60.7 Notification and recordkeeping.

    b. §60.8 Performance tests.

    c. §60.11 Compliance with standards and maintenance requirements.

d. §60.12 Circumvention.

e. §60.13 Monitoring requirements.

f. §60.14 Modification.

g. §60.15 Reconstruction.

h. §60.18 General control device requirements.

i. §60.19 General notification and reporting requirements.

12. 40 CFR Part 61 Subpart A applies to equipment subject to National Emissions Standards for Hazardous Air Pollutants under Part 61. Unless applicable subparts specify otherwise, the permittee shall comply with all applicable standards of Subpart A, including but not limited to, the following: [40 CFR Part 61 Subpart A]

a. §61.07 Application for approval of construction or modification.

b. §61.09 Notice of startup.

c. §61.10 Source reporting and waiver request.

d. §61.12 Compliance with standards and maintenance requirements.

e. §61.13 Emission tests and waiver of emission tests.

f. §61.14 Monitoring requirements.

g. §61.15 Modification.

13. 40 CFR Part 63 Subpart A applies to all equipment subject to National Emissions Standards for Hazardous Air Pollutants under Part 63. Unless specific applicable subparts specify otherwise, the permittee shall comply with all applicable requirements of Subpart A, including but not limited to the following: [40 CFR Part 63 Subpart A]

a. §63.5 Preconstruction review and notification requirements.

b. §63.6 Compliance with standards and maintenance requirements.

c. §63.7 Performance testing requirements.

d. §63.8 Monitoring requirements.

e. §63.9 Notification requirements.

f. §63.10 Recordkeeping requirements.

g. §63.11 Control device requirements.

14. Reserved.

15. Reserved.

16. All gases from the No. 1, No. 2, and No. 3 Amine Recovery Units shall be sent to an on-site sulfur recovery unit (SRU) or off-site sulfur recovery facility. [OAC 252:100-8-6(a)]

17. Tanks T-0078E, T-0304, T-0305, and T-0915 shall not be utilized for hydrocarbon or oily wastewater service. [OAC 252:100-8-6(a)]

18. Reserved.

19. Each six-month period, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. The initial semiannual report shall be postmarked no later than May 30th and shall cover the reporting period beginning November 1st of the preceding year and ending April 31st of the current year. The second semiannual report shall be postmarked no later than November 30th and shall cover the reporting period beginning May 1st of the current year and ending October 31st of the current year.
[252:100-8-6(a)(3)(C)(i), (ii), & (iv)]

20. Each calendar year, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since issuance of this permit. The compliance certification shall also include such other facts as the permitting authority may require in order to determine the compliance status of the source. The annual compliance report shall be postmarked no later than November 30th and shall cover the annual compliance period beginning November 1st of the preceding year and ending October 31st of the current year.
[OAC 252:100-8-6 (c)(5)(A) & (D)]

21. This permit does not supersede or cancel any previously issued Air Quality permits for this facility.

22. The Permit Shield (Standard Conditions, Section VI) is extended to the following requirements that have been determined to be inapplicable to this facility.
[OAC 252:100-8-6(d)(2)]

a. OAC 252:100-11 Alternative Emissions Reduction

b. OAC 252:100-17 Incinerators

c. OAC 252:100-23 Cotton Gins

d. OAC 252:100-24 Grain Elevators

e. OAC 252:100-39 Nonattainment Areas

f. OAC 252:100-47 Landfills

g. 40 CFR Parts 72, 73, 74, 75, and 76 Acid Rain

23. This facility is considered an existing Prevention of Significant Deterioration (PSD) facility. As such, the facility is subject to the provisions of OAC 252:100-8-36.2(c) for any project as defined therein. [OAC 252:100-8-36.2(c)]

a. The facility shall maintain records as required by OAC 252:100-8-36.2(c).

i. For 5 calendar years after startup of the "Coke Drum Replacement projects" authorized by construction permit, the permittee shall track CO, VOC, $PM_{10/2.5}$, NOx, H_2S and SO_2 emissions and maintain records to demonstrate emission increases are below PSD thresholds for the following sources: H-0023, H-0028, H-0029, H-0046, No. 5 FCCU, No. 7 Coker Coke Drum Handling Operations and No. 7 Coker Coke Pad.

ii. For 10 calendar years after startup of the "2015-2017 LRP Projects" authorized by construction permit, the permittee shall track CO, VOC, $PM_{10/2.5}$, NO_X, H_2S and SO_2 emissions and maintain records to demonstrate emission increases are below PSD thresholds for the following sources: H-0001, H-0016, H-0010, H-0011, H-0023, H-0028, H-0029, H-0046, H-0048, H-0060, H-1001, H-5002, H-6005, H-6008, H-6007, H-6012, H-6013, H-6014, H-6015, H-6151, H-7501, H-9301, H-9901, H-9902, H-8601, H-8602, H-8801/H-8802, H-9851, B-0008, No. 4 FCCU, No. 5 FCCU, South Crude Tank Farm, Wastewater Treatment, No. 7 Coker Coke Drum Handling Operations and No. 7 Coker Coke Pad.

iii. For 10 calendar years after startup of the "2020-2022 LRP Projects" authorized by construction permit, the permittee shall track VOC, $PM_{10/2.5}$, NO_X, H_2S, and SO_2 emissions and maintain records to demonstrate emission increases are below PSD thresholds for the following sources: H-0003, H-0004, H-0010, H-0011, H-0023, H-0028, H-0029, H-0046, H-0048, H-5002, H-6007, H-6012, H-6013, H-6151, H-7501, H-9301, H-9901, H-9902, H-8601, H-8602, H-9851, No. 4 FCCU, No. 5 FCCU, South Crude Tank Farm, Wastewater Treatment, No. 7 Coker Coke Drum Handling operations, and No. 7 Coker Coke Pad.

24. Within 180 days of commencement of operation of any of the modifications authorized by this construction permit, the owner/operator shall submit an administratively complete operating permit application to incorporate these modifications into the Title V operating permit. [OAC 252:100-8-4(b)(5)]

Phillips 66 Company
Attn: Mr. Chad Sheetz
1000 South Pine, 1230 RB
Ponca City, OK 74601

SUBJECT: Permit No. **2012-704-C (M-17) PSD**
Phillips 66 Company, Ponca City Refinery
AQD Facility ID No. 314
Latitude 36.68807°N, Longitude 97.08786°W
Sections 33 & 34, Township 26N, Range 2E
Sections 3 & 4, Township 25N, Range 2E
Kay County, Oklahoma

Dear Mr. Sheetz:

Enclosed is the permit authorizing construction of the referenced facility. Please note that this permit is issued subject to the standard and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emissions inventory for this facility. An emissions inventory must be completed through DEQ's electronic reporting system by April 1st of every year. Any questions concerning the submittal process should be referred to the Emissions Inventory Staff at (405) 702-4100.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me or Joseph Wills, the permit writer, at Joseph.Wills@deq.ok.gov or (405) 702-4100.

Sincerely,

DRAFT/PROPOSED

Phillip Fielder, P.E.
Chief Engineer
AIR QUALITY DIVISION

NSR CONSTRUCTION PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 N. ROBINSON STREET, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 2012-704-C (M-17) PSD

Phillips 66 Company,

having complied with the requirements of the law, is hereby granted permission to modify the Ponca City Refinery located in Ponca City, Kay County, Oklahoma, subject to the Standard Conditions dated June 21, 2016, and the Specific Conditions, which are both attached.

In the absence of commencement of construction, the permit shall expire 18 months from the issuance date, except as authorized under Section VIII of the Standard Conditions.

DRAFT/PROPOSED

Kendal Stegmann, Division Director **Date**
AIR QUALITY DIVISION

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(June 21, 2016)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.
[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:

(1) the date, place and time of sampling or measurement;
(2) the date or dates analyses were performed;
(3) the company or entity which performed the analyses;
(4) the analytical techniques or methods used;
(5) the results of such analyses; and
(6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions. [OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants ("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality. [OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.

[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or

intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source. [OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.
[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing,

terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.
[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.
[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.
[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.
[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d). [OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.
[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(17) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;

(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.
[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.
[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]

(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]

(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]

(a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
(b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
(c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
(d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of

adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;
(3) Persons performing maintenance, service, repair, or disposal of appliances must be

certified by an approved technician certification program pursuant to § 82.161;
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).
(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).
(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
(6) The DEQ complies with 40 C.F.R. § 70.8(d).
(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).
(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.
(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. [OAC 252:100-43-6]

Department of Environmental Quality (DEQ)
Air Quality Division (AQD)
Acronym List
11-21-2024

ACFM	Actual Cubic Feet per Minute
AD	Applicability Determination
AFRC	Air-to-Fuel Ratio Controller
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
AVO	Audio, Visual, or Olfactory
BACT	Best Available Control Technology
BAE	Baseline Actual Emissions
BBL	Barrel(s)
BHP	Brake Horsepower (bhp)
BTEX	Benzene, Toluene, Ethylbenzene, Xylene
BTU	British thermal unit (Btu)
C&E	Compliance and Enforcement
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CAS	Chemical Abstract Service
CAAA	Clean Air Act Amendments
CC	Catalytic Converter
CCR	Continuous Catalyst Regeneration
CD	Consent Decree
CEM	Continuous Emission Monitor
CFC	Chlorofluorocarbon
CFR	Code of Federal Regulations
CI	Compression Ignition
CNG	Compressed Natural Gas
CO	Carbon Monoxide or Consent Order
COA	Capable of Accommodating
COM	Continuous Opacity Monitor
D	Day
DEF	Diesel Exhaust Fluid
DG	Demand Growth
DSCF	Dry Standard (At Standard Conditions) Cubic Foot (Feet)
EGU	Electric Generating Unit
EI	Emissions Inventory
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
EUG	Emissions Unit Group
EUSGU	Electric Utility Steam Generating Unit
FCE	Full Compliance Evaluation
FCCU	Fluid Catalytic Cracking Unit
FEL	Federally Enforceable Limit(s)
FIP	Federal Implementation Plan
FR	Federal Register
GACT	Generally Achievable Control Technology
GAL	Gallon (gal)
GDF	Gasoline Dispensing Facility
GEP	Good Engineering Practice
GHG	Greenhouse Gases
GR	Grain(s) (gr)
H_2CO	Formaldehyde
H_2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutants
HC	Hydrocarbon
HCFC	Hydrochlorofluorocarbon
HFR	Horizontal Fixed Roof
HON	Hazardous Organic NESHAP
HP	Horsepower (hp)
HR	Hour (hr)
I&M	Inspection and Maintenance
IBR	Incorporation by Reference
ICE	Internal Combustion Engine
LAER	Lowest Achievable Emission Rate
LB	Pound(s) [Mass] (lb, lbs, lbm)
LB/HR	Pound(s) per Hour (lb/hr)
LDAR	Leak Detection and Repair
LNG	Liquefied Natural Gas
LT	Long Ton(s) (metric)
LPE	Legally and Practicably Enforceable
M	Thousand (Roman Numeral)
MAAC	Maximum Acceptable Ambient Concentration
MACT	Maximum Achievable Control Technology
MM	Prefix used for Million (Thousand-Thousand)
MMBTU	Million British Thermal Units (MMBtu)
MMBTUH	Million British Thermal Units per Hour (MMBtu/hr)
MMSCF	Million Standard Cubic Feet (MMscf)
MMSCFD	Million Standard Cubic Feet per Day
MSDS	Material Safety Data Sheet
MWC	Municipal Waste Combustor
MWe	Megawatt Electrical
NA	Nonattainment
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System

NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	Ammonia
NMHC	Non-methane Hydrocarbon
NGL	Natural Gas Liquids
NO_2	Nitrogen Dioxide
NOx	Nitrogen Oxides
NOI	Notice of Intent
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standards
NSR	New Source Review
O_3	Ozone
O&G	Oil and Gas
O&M	Operation and Maintenance
O&NG	Oil and Natural Gas
OAC	Oklahoma Administrative Code
OC	Oxidation Catalyst
OGI	Optical Gas Imaging
PAH	Polycyclic Aromatic Hydrocarbons
PAE	Projected Actual Emissions
PAL	Plant-wide Applicability Limit
Pb	Lead
PBR	Permit by Rule
PCB	Polychlorinated Biphenyls
PCE	Partial Compliance Evaluation
PEA	Portable Emissions Analyzer
PFAS	Per- and Polyfluoroalkyl Substance
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter with an Aerodynamic Diameter <= 2.5 Micrometers
PM_{10}	Particulate Matter with an Aerodynamic Diameter <= 10 Micrometers
POM	Particulate Organic Matter or Polycyclic Organic Matter
ppb	Parts per Billion
ppm	Parts per Million
ppmv	Parts per Million Volume
ppmvd	Parts per Million Dry Volume
PSD	Prevention of Significant Deterioration
psi	Pounds per Square Inch
psia	Pounds per Square Inch Absolute
psig	Pounds per Square Inch Gage
RACT	Reasonably Available Control Technology
RATA	Relative Accuracy Test Audit
RAP	Regulated Air Pollutant or Reclaimed Asphalt Pavement
RFG	Refinery Fuel Gas
RICE	Reciprocating Internal Combustion Engine
RO	Responsible Official
ROAT	Regional Office at Tulsa
RVP	Reid Vapor Pressure
SCC	Source Classification Code
SCF	Standard Cubic Foot
SCFD	Standard Cubic Feet per Day
SCFM	Standard Cubic Feet per Minute
SCR	Selective Catalytic Reduction
SER	Significant Emission Rate
SI	Spark Ignition
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SOx	Sulfur Oxides
SOP	Standard Operating Procedure
SRU	Sulfur Recovery Unit
T	Tons
TAC	Toxic Air Contaminant
TEG	Triethylene Glycol
THC	Total Hydrocarbons
TPY	Tons per Year
TRS	Total Reduced Sulfur
TSP	Total Suspended Particulates
TV	Title V of the Federal Clean Air Act
$\mu g/m^3$	Micrograms per Cubic Meter
US EPA	U. S. Environmental Protection Agency
VFR	Vertical Fixed Roof
VMT	Vehicle Miles Traveled
VOC	Volatile Organic Compound
VOL	Volatile Organic Liquid
VRT	Vapor Recovery Tower
VRU	Vapor Recovery Unit
YR	Year
2SLB	2-Stroke Lean Burn
4SLB	4-Stroke Lean Burn
4SRB	4-Stroke Rich Burn

Robert Singletary
Executive Director

OKLAHOMA Environmental Quality

Kevin Stitt
Governor

April 14, 2024

Phillips 66 Company
Attn: Mr. Chad Sheetz
1000 South Pine, 1230 RB
Ponca City, OK 74601

SUBJECT: Permit No. **2012-704-C (M-17) PSD**
Phillips 66 Company, Ponca City Refinery
AQD Facility ID No. 314
Latitude 36.68807°N, Longitude 97.08786°W
Sections 33 & 34, Township 26N, Range 2E
Sections 3 & 4, Township 25N, Range 2E
Kay County, Oklahoma

Dear Mr. Sheetz:

Air Quality has received the permit application for the referenced facility and completed initial review. This application has been determined to be a Tier II application. In accordance with 27A O.S. 2-14-301 and 302 and OAC 252:4-7-13(c), the enclosed draft permit is now ready for public review. The requirements for public review of the application and draft permit include the following steps, which **you** must accomplish:

1. Publish at least one legal notice (one day) for the Notice of Tier II Draft Permit in at least one newspaper of general circulation within the county where the facility is located (Instructions enclosed);
2. Submit sample notice and provide date of publication to **AQD 5 days prior to notice publishing;**
3. Provide for public review, for a period of 30 days following the date of the newspaper announcement, a copy of the application and draft permit at a convenient location (preferentially at a public location) within the county of the facility;
4. Send AQD a signed affidavit of publication for the notice(s) from Item #1 above within 20 days of publication of the draft permit. Any additional comments or requested changes you have for the draft permit or the application should be submitted within 30 days of publication.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me or the permit writer at (405) 702-4100.

Sincerely,

Eric L. Milligan, P.E.
Engineering Manager
AIR QUALITY DIVISION

NOTICE OF DRAFT PERMIT
TIER II or TIER III AIR QUALITY PERMIT APPLICATION

APPLICANT RESPONSIBILITIES

Permit applicants are required to give public notice that a Tier II or Tier III draft permit has been prepared by DEQ. The notice must be published in one newspaper local to the site or facility. Note that if either the applicant or the public requests a public meeting, this must be arranged by the DEQ.

1. Complete the public notice using the samples provided by AQD below. Please use the version applicable to the requested permit action;
   Version 1 – Traditional NSR process for a construction permit
   Version 2 – Enhanced NSR process for a construction permit
   Version 3 – initial Title V (Part 70 Source) operating permit, Title V operating permit renewal, Significant Modification to a Title V operating permit, and any Title V operating permit modification incorporating a construction permit that followed Traditional NSR process
2. Determine appropriate newspaper local to facility for publishing;
3. Submit sample notice and provide date of publication to AQD 5 days prior to notice publishing;
4. Upon publication, a signed affidavit of publication must be obtained from the newspaper and sent to AQD.

REQUIRED CONTENT (27A O.S. § 2-14-302 and OAC 252:4-7-13(c))

1. A statement that a Tier II or Tier III draft permit has been prepared by DEQ;
2. Name and address of the applicant;
3. Name, address, driving directions, legal description and county of the site or facility;
4. The type of permit or permit action being sought;
5. A description of activities to be regulated, including an estimate of emissions from the facility;
6. Location(s) where the application and draft permit may be reviewed (a location in the county where the site/facility is located must be included);
7. Name, address, and telephone number of the applicant and DEQ contacts;
8. Any additional information required by DEQ rules or deemed relevant by applicant;
9. A 30-day opportunity to request a formal public meeting on the draft permit.

SAMPLE NOTICE *(Italicized print is to be filled in by the applicant.)***:**

Version 2 – For those using the Enhanced NSR Process for a construction permit application review

DEQ NOTICE OF TIER *…II or III…* **DRAFT PERMIT**

A Tier *…II or III…* **application for an air quality construction permit for a modification at an existing major facility has been filed with the Oklahoma Department of Environmental Quality (DEQ) by applicant,** *…name and address.*

The applicant requests approval to *…brief description of purpose of application…* **at the** *…site/facility name … …***[proposed to be] located at** *…physical address (if any), driving directions, and legal description including county…..*

In response to the application, DEQ has prepared a draft construction permit (Permit Number: *…xxxx-xxxx-x…***), which may be reviewed at** *…locations (one must be in the county where the site/facility is located)…* **or at the Air Quality Division's main office (see address below). The draft permit is also available for review under Permits for Public Review on the DEQ Web Page: https://www.deq.ok.gov/**

This draft permit would authorize the facility to emit the following regulated pollutants: *(list each pollutant and amounts in tons per year (TPY))***, which represents** (*identify the emissions change (increase or decrease) involved in the modification)***. [**Or add: **The modification will not result in a change in emissions.**] [For PSD permits only, add**: The project will consume the following increment levels:** *(list the amount of increment consumption for each pollutant in ug/m^3).*]

The public comment period ends 30 days after the date of publication of this notice. Any person may submit written comments concerning the draft permit to the Air Quality Division contact listed below or as directed through the corresponding online notice. Only those issues relevant to the proposed modification(s) are open for comment. A public meeting on the draft permit may also be requested in writing at the same address. Note that all public meetings are to be arranged and conducted by DEQ staff.

In addition to the public comment opportunity offered under this notice, this draft permit is subject to U.S. Environmental Protection Agency (EPA) review, EPA objection, and petition to EPA, as provided by 40 CFR § 70.8. The requirements of the construction permit will be incorporated into the Title V operating permit through the administrative amendment process. Therefore, no additional opportunity to provide comments or EPA review, EPA objection, and petitions to EPA will be available to the public when requirements from the construction permit are incorporated into the Title V operating permit.

If the Administrator (EPA) does not object to the proposed permit, the public has 60 days following the Administrator's 45-day review period to petition the Administrator to make such an objection as provided in 40 CFR 70.8(d) and in OAC 252:100-8-8(j).

Information on all permit actions including draft permits, proposed permits, final issued permits and applicable review timelines are available in the Air Quality section of the DEQ Web page: https://www.deq.ok.gov/.

For additional information, contact *…names, addresses and telephone numbers of contact persons for the applicant,* **or contact DEQ at: Chief Engineer, Air Quality Division, 707 N. Robinson, Suite 4100, P.O. Box 1677, Oklahoma City, OK, 73101-1677. Phone No. (405) 702-4100.**

Robert Singletary
Executive Director

OKLAHOMA Environmental Quality

Kevin Stitt
Governor

April 14, 2025

Kansas Department of Health & Environmental
Bureau of Air
1000 SW Jackson, Ste 310
Topeka, Kansas 66612-1366

SUBJECT: Permit No. **2012-704-C (M-17) PSD**
Phillips 66 Company, Ponca City Refinery
AQD Facility ID No. 314
Latitude 36.68807°N, Longitude 97.08786°W
Sections 33 & 34, Township 26N, Range 2E
Sections 3 & 4, Township 25N, Range 2E
Kay County, Oklahoma
Permit Writer: Joseph K. Wills, P.E.

Dear Sir / Madame:

The subject facility has requested a modification to an NSR construction permit for a Part 70 source. Air Quality Division has completed the initial review of the application and prepared a draft permit for public review. Since this facility is within 50 miles of the Oklahoma - Kansas border, a copy of the draft permit will be provided to you upon request. The draft permit is also available for review on the Air Quality section of the DEQ web page at *https://www.deq.ok.gov*.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me or the permit writer at (405) 702-4100.

Sincerely,

Eric L. Milligan, P.E.
Engineering Manager
AIR QUALITY DIVISION