OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **December 17, 2004**

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THROUGH: Peer Review

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SUBJECT: Evaluation of Permit Application **No. 2003-336-C (M-1) PSD**
ConocoPhillips Company, Ponca City Refinery
Ultra-Low Sulfur Diesel & Upgrade Projects (ULSD Project)
Ponca City, Kay County, Oklahoma

SECTION I. INTRODUCTION

ConocoPhillips Company owns and operates the Ponca City Refinery (the refinery) which is located just south of Ponca City, Oklahoma, and is divided into five main areas based on the layout of the operations: East Plant, West Plant, South Plant, Coker Combo, and Oil Movements. Each area consists of major processing units and other supplementary units that aid in the refining operations.

The refinery is a Title V major source and is located in an area designated as attainment for all criteria air pollutants. The refinery submitted an initial Part 70 Permit application (Permit Number 98-104-TV) on March 17, 1998 that is under review by AQD. The primary Standard Industrial Classification (SIC) code for the refinery is 2911 (Petroleum Refining). The refinery is an existing major source for the Federal Prevention of Significant Deterioration (PSD) program and a Maximum Achievable Control Technology (MACT) source category regulated under 40 CFR Part 63, Subpart CC (MACT I) and Subpart UUU (MACT II).

The ULSD project is being installed to meet future U.S. EPA standards for sulfur concentration in highway diesel fuel. On January 21, 2001, the U.S. EPA published the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements rule that required refiners to lower the sulfur content in diesel from 500 parts per million (ppm) to 15 ppm by June 1, 2006. Construction of the ULSD project is scheduled to begin during the 3rd quarter of 2004.

All of the new and modified process heaters and boilers for this project will be constructed or modified with ultra-low NO_X ($ULNO_X$) burners to provide reduced NO_X and CO emissions.

On September 9, 2004, ConocoPhillips requested a minor modification of Permit No. 2003-336-C PSD to make several changes as follows:

1. Revise Specific Condition 1.B.x to more accurately reflect the requirements of Consent Decree C.A. H-01-4430 (A) (the Consent Decree) as it pertains to performance testing for NO_X and CO emissions from Heaters H-6015 and H-5001.
2. Revise Specific Condition 1.B to reflect the fact that Heaters H-0057, H-0058, and H-0059 share one stack. The combined duty of the heaters will now be greater than 150 MMBtu/hr and the Consent Decree requires Continuous Emissions Monitoring Systems (CEMS) for NO_X and CO in the common stack. A new specific condition will be added for this requirement.
3. New boilers B-9 and B-10 will be constructed with a common stack. Revise Specific Condition 1.C to reflect this change.
4. Revise Specific Condition No. 1.D.i to clarify when certain emission limits for the No. 4 FCCU and the No. 5 FCCU, as required by the Consent Decree, go into effect.
5. Revise Specific Condition No. 1.D.iii to include a statement that "this specific condition supercedes Specific Condition 12 of Permit No. 2000-206-C (M-4)."
6. Revise Specific Condition No. 1.D by increasing the SO_2 emission limits for the No. 4 FCCU from 24.0 lb/hr and 105 TPY to 76.0 lb/hr and 333 TPY. ConocoPhillips is presently conducting SO_2 reducing additive demonstrations for the No. 4 FCCU as required by the Consent Decree. However, it appears that NO_X reducing additives interfere with the performance of the SO_2 reducing additives. The EPA has given ConocoPhillips approval to extend the SO_2 additive testing by an additional 12 months to June 30, 2005. This will result in higher SO_2 emissions from the No. 4 FCCU than were expected and that were used in the PSD netting analysis for Permit No. 2003-336-C PSD. However, the SO_2 reductions expected from the use of SO_2 reducing additives for the No. 4 FCCU were not creditable for PSD netting purposes since such reductions were required by the Consent Decree. Therefore, the results of the PSD netting analysis in Permit No. 2003-336-C PSD are the same and no analysis revision is required in this permit, other than changing the SO_2 emissions increases for the No. 4 FCCU from a minus 387 TPY to a minus 159 TPY. Since the potential SO_2 emissions for the No. 4 FCCU will be higher than those used in Permit No. 2003-336-C PSD, ConocoPhillips performed another ambient air analysis to show compliance with the SO_2 ambient air standards of OAC 252:100-31. No significant deviation from the previous modeling resulted and compliance with Subchapter 31 was demonstrated.

Revisions 1, 4, and 5 may be considered administrative changes, while revisions 2, 3, and 6 are minor modifications to the construction permit. The previous PSD applicability, PSD netting analysis, and PSD review for CO and VOC (including BACT analysis) for Permit No. 2003-336-C PSD are still applicable.

SECTION II. PROJECT SUMMARY

Projects

With this application ConocoPhillips is requesting a permit to:

1. Install the Ultra-Low Sulfur Diesel Project (ULSD) including:
    - Expansion of the existing Kerosene Hydrotreater (No. 4 HDT)
    - Modification of the existing Diesel Hydrotreater (No. 6 HDT)
    - Construction of a new Diesel Hydrotreater (No. 9 HDT)
    - Construction of a new Hydrogen Plant (H_2 Plant)
    - Construction of a new Sour Water Stripper (SWS)
    - Construction of a new hydrocarbon liquid storage tank (T-1101)
2. Install two new 600-psig steam boilers (B-0009 and B-0010)
3. Modify the Saturated Gas Plant (SGP)
4. Modify the No. 2 Crude Topping Unit (No. 2 CTU)
5. Modify the No. 4 Fluidized Catalytic Cracking Unit (No 4. FCCU)
6. Modify/Replace the Main Furnace (H-6007) of the No. 3 Catalytic Reformer Unit (No. 3 CRU)
7. Modify the No. 5 Fluidized Catalytic Cracking Unit (No. 5 FCCU), and
8. Modify the HF Alkylation Unit (Alky)

The two new 600-psig steam boilers, with a common stack, will be built to replace the steam production capacity that will be lost due to the shutdown of the two Cogeneration Units located at the refinery. The Cogeneration Units are made up of two combustion turbines and two heat recovery steam generators (HRSGs), each of which includes supplemental duct burners. Construction of the new boilers is planned to begin during the first half of 2005.

In addition to the ULSD project and new boilers, a series of upgrade projects are scheduled during near-term unit turnarounds.

The SGP project will improve light hydrocarbon recovery and fractionation. Also included are modifications made as a part of the SGP fire rebuild per the requirements of Consent Order No. 03-254 (Order), which was agreed to on August 1, 2003, by the Department of Environmental Quality (DEQ) and ConocoPhillips in order to resolve issues of temporary construction, repair, and replacement at the refinery. A hydrocarbon release and fire occurred at the refinery on July 21, 2003.

The No. 2 CTU project will improve product yields and remove a number of existing bottlenecks in order to increase the unit's crude oil feed capacity and process "price advantaged" crude oils.

The No. 4 FCCU project will improve yields of high value products such as gasoline and diesel oil.

The No. 3 CRU project will replace or modify reformer main furnace H-6007 to reduce emissions and improve mechanical integrity.

The No. 5 FCCU project will remove a number of existing bottlenecks in order to increase the unit's fresh feed capacity and/or improve yields of high value products.

The Alky project will enable the unit to process the increased capacity resulting from the previously mentioned modification projects.

In addition to the projects listed above, a new Sulfur Recovery Unit (SRU) will be built at the Jupiter facility neighboring the refinery. Jupiter will handle the construction and permitting of the new SRU.

ConocoPhillips is subject to Civil Action H-01-4430 (the Consent Decree) entered in the Southern District Court for Texas on April 30, 2002 and amended on August 5, 2003, which requires the refinery to undertake certain emission reduction actions. The following projects and activities are necessary for the refinery to comply with the Consent Decree:

- Installation of $ULNO_X$ burners in No. 2 CTU heaters H-6014 and H-6015
- Installation of $ULNO_X$ burners in No. 5 FCCU heater H-5001
- Installation of $ULNO_X$ burners in Alky heaters H-57, H-58 and H-59
- Shutdown of, or installation of $ULNO_X$ burners in, No. 3 CRU heater H-6007
- Use of emissions reduction additives (low-NO_X combustion promoter and NO_X and SO_X reducing additives) in the No. 4 FCCU
- Use of emissions reduction additives (low-NO_X combustion promoter and NO_X reducing additive) in the No. 5 FCCU
- Installation of a Selective Non-Catalytic Reduction (SNCR) unit in No. 5 FCCU CO boiler B-5004
- Installation of a wet gas scrubber (WGS) on the No. 5 FCCU regenerator/CO boiler stack
- Implementation of equipment and/or instrumentation that support good air pollution control practices as approved by EPA on the South Plant and East Plant flare stacks including, but not limited to, installation of new flare gas recovery units (FGRU), tie-in to existing FGRUs, installation of Sulfur Sorbers (H_2S adsorber catalyst bed), and/or installation of H_2S CEMS instrumentation

PSD Applicability

Emissions decreases resulting from compliance with the Consent Decree are not creditable for PSD netting purposes. However, these decreases are accounted for in the air quality modeling.

As summarized in Table II-1, emissions attributable to projects not related to the Consent Decree that are included in this permit exceed PSD significance levels for CO and VOC. These projects, when combined with other planned and completed projects in the contemporaneous netting period, show a net reduction in NO_X and SO_2. The net emission increase for PM_{10} is below the PSD significant emissions rate (SER). Therefore, the proposed changes are subject to PSD permitting requirements for CO and VOC only. The PSD review for this permit also requires an air quality analysis to estimate the ambient impacts of emissions from the project (OAC 252:100-8-35). A

full PSD analysis including an air quality analysis is presented in Section V of this memorandum.

Table II-1. Net Emissions Increase For PSD Regulated Pollutants

Pollutant	Emission Rate, TPY	PSD Significant Emission Rate, TPY	Subject to PSD Review?
CO	283	100	Yes
PM_{10}	14.9	15	No
NO_X	6	40	No
SO_2	-503	40	No
VOC	83	40	Yes

BACT

As part of the PSD review process, a Best Available Control Technology (BACT) analysis is required for each pollutant that is emitted in excess of its PSD Significant Emission Rate. The BACT analysis is based on the most effective technology currently available, with consideration for energy, environmental, and economic factors. The results of the BACT analysis form the basis for the selection of control technology and the resulting emission limitations for each emissions unit. The BACT analyses for the new and modified emissions units for this project are summarized in Table II-2. A detailed discussion of the BACT analyses is given in Section V of this memorandum.

Table II-2. Summary of Proposed BACT

EQUIPMENT	POLLUTANT	BACT DESCRIPTION
Process Heaters & Boilers	CO VOC	Good Combustion Practice Good Combustion Practice
Equipment Leaks	VOC	40 CFR Part 63, Subpart CC (Refinery MACT)
Storage Tanks	VOC	40 CFR Part 63, Subpart CC (Refinery MACT)
Cooling Tower	VOC	Monthly Monitoring, Inspection, and Maintenance Plan (MIMP)
No. 4 FCCU	CO VOC	CO Combustion Promoter Good Combustion Practice
No. 5 FCCU	CO VOC	CO Boiler & CO Combustion Promoter Good Combustion Practice
H_2 Plant Deaerator Vent	VOC	Proper Equipment Operation

SECTION III. PROCESS AND PROJECT DISCRIPTION

The ConocoPhillips Ponca City Refinery is a fully integrated facility operating three crude units, two fluidized catalytic cracking units, a coker, and other major upgrading units to produce petrochemical feedstocks, gasoline, heating oil, residual fuels, petroleum coke, and other miscellaneous petroleum products. The refinery is a modern, full upgrading facility. Major process units include:

- Fluid catalytic cracking units to upgrade gas oil to gasoline and diesel fuel
- Alkylation, polymerization and catalytic reforming units to produce high octane gasoline blending components
- A coker to crack/convert residuals into lighter hydrocarbon compounds and produce anode grade coke for aluminum manufacturing
- Multiple desulfurization units
- Amine contactors and regenerators and a sulfur recovery unit to remove sulfur from products and intermediates, allowing production of low sulfur products from high sulfur feedstocks

The following sections describe the process units affected by the proposed projects.

Ultra-Low Sulfur Diesel Project

The Ultra-Low Sulfur Diesel (ULSD) project, scheduled to begin construction during the 3rd quarter of 2004, is an end-of-the-line treatment process for the diesel oil currently being produced by the refinery. This project does not increase diesel oil production. The ULSD project will consist of a new diesel hydrotreater (No. 9 HDT), a new sour water stripper, a new Hydrogen Plant (H_2 Plant), expansion of the existing kerosene hydrotreater (No. 4 HDT), and modification of the existing diesel hydrotreater (No. 6 HDT).

The No. 9 HDT will be a conventional hydrotreater that will be used to remove sulfur and nitrogen compounds from refinery-produced diesel oil streams by combining them with high-pressure, high-purity hydrogen gas. The combined diesel oil and hydrogen stream will be heated in a gas-fired furnace, H-9901, and passed through a reactor where the sulfur compounds will be converted to hydrogen sulfide and the nitrogen compounds will be converted to ammonia. The reactor effluent stream will be cooled and separated into two streams. One of the streams is a gas stream containing hydrogen, hydrogen sulfide, and ammonia. The other stream is a low-sulfur (<15 ppm) liquid hydrocarbon stream. The gas stream will be treated with an amine solution that absorbs the hydrogen sulfide. The rich amine solution will be regenerated to recover the hydrogen sulfide, which will be sent to the refinery Sulfur Recovery Unit (SRU) or to the Jupiter facility neighboring the refinery. The treated hydrogen stream is recycled to the hydrotreater. The low-sulfur liquid hydrocarbon stream will be sent to a stripper column, which will include gas-fired reboiler H-9902, for removal of any residual hydrogen sulfide and light ends material. The stripper bottoms (stabilized low-sulfur diesel) will then be cooled and sent to storage. The stripper overhead naphtha stream will be sent to storage prior to further processing. The stripper overhead gas stream will be sent to the refinery fuel gas system.

Ammonia formed in the hydrotreater will be absorbed into process water, which will leave the unit as sour water. The sour water will be processed in the sour water stripper to remove hydrogen sulfide and ammonia before being sent to the No. 5 FCCU for reuse or sent to the Activated Sludge Unit (ASU). Sour water from the refinery-wide collection system will be heated in a feed/bottoms heat exchanger and sent to the sour water stripper tower. A steam-heated reboiler will provide reboil heat for the tower. Stripped water from the bottom of the tower will be cooled in the feed/bottoms exchanger and then by an air-cooled exchanger. The stripper tower overhead stream, which contains primarily hydrogen sulfide, ammonia, and water vapor, will be sent to the Jupiter facility neighboring the refinery. A new sour water stripper and associated equipment are included in the ULSD project and will operate in parallel with the existing sour water stripper.

A new hydrogen plant is included in the ULSD project to supply makeup hydrogen to the new and existing refinery hydrotreaters. The hydrogen plant will use pipeline quality natural gas and/or refinery fuel gas (RFG) as feed gas and fuel gas. The feed gas will flow through guard desulfurizers to the hydrogen plant reformer heater, ULSD-5/5a, and then to a shift converter. From the shift converter, the stream will flow through a heat exchanger to a hot condensate separator. Gas from the separator will be cooled and sent through a series of parallel, pressure swing adsorbers (PSAs). From the PSAs, the hydrogen gas will be sent to the refinery hydrogen system. The PSA off gas, consisting primarily of CO_2 and smaller amounts of CO, hydrogen, and methane, will be sent to the ULSD-5/5a firebox to be combusted.

Other new equipment included in the ULSD project is a 100,000-barrel hydrocarbon liquid storage tank.

Modification of the No. 4 HDT in support of the ULSD project will include installation of new feed heater H-1001 to replace existing heater H-0047, which will be removed from service. Additional modifications will include, but not be limited to, replacement and modification of process vessels, heat exchangers, pumps, control valves, piping, instrumentation, and other associated equipment in order to increase the unit feed capacity.

Modification of the No. 6 HDT in support of the ULSD project will include, but will not be limited to, addition of two new rows of tubes in the convection section of heater H-7501, replacement and modification of process vessels, reactor vessels, heat exchangers, pumps, control valves, piping, instrumentation, and other associated equipment. No modifications will be made to heater H-7501 that will increase its fired duty capacity.

High-Pressure Steam Boilers

Two new RFG-fired mechanical draft boilers will be installed at the refinery to replace the steam production capacity that will be lost due to the shutdown of the two Cogeneration Units located at the refinery. The Cogeneration Units will be shutdown during the first half of 2006. Each new boiler will be designed to produce 250,000 lb/hr of 600-psig steam. Construction of the new boilers and the boiler feed water (BFW) pump is scheduled to begin during the first half of 2005.

Saturated Gas Plant

The purpose of the Saturated Gas Plant (SGP) is to recover low boiling point (<220 ºF) saturated hydrocarbons produced by other refinery units. The feed streams to the SGP include unstabilized light straight-run gasoline (LSR), crude unit overhead gases, catalytic reformer overhead gases and liquids, and gasoline hydrotreater (No. 7 HDT) overhead liquids and gases.

The SGP feed streams yield fuel gas, propane, butanes, and straight-run gasoline stabilized at a desired Reid Vapor Pressure (RVP). Volatile components are removed from the gasoline feed to meet regulatory requirements for fuel volatility.

The propane stream is treated to remove hydrogen sulfide (H_2S). The stabilized light straight-run gasoline stream is sent to the No. 7 HDT to remove mercaptans and H_2S. The stabilized heavy straight-run gasoline stream is sent to the Merox Unit for sweetening.

There are four principal sections in the SGP: stabilization, absorption/stripping, amine treating, and Merox sweetening.

The SGP LSR feed drum receives unstabilized LSR from the refinery crude topping units (CTUs) and serves as a surge drum for the SGP. The combined LSR stream is split to feed two SGP stabilizers, which remove propane and butane from the unstabilized LSR feed stream. A portion of the bottom stream from one of the stabilizers is pumped to the top of the SGP absorber column as absorbing oil. This stream is ultimately recycled back to the stabilizer.

The LSR streams from the two stabilizers (stabilized LSR) are combined and fed to the No. 7 HDT LSR/naphtha splitter column where stabilized LSR is separated from naphtha. Stabilized LSR is treated for mercaptan and H_2S removal in the No. 7 HDT. The naphtha stream is sent back to the SGP Heavy Straight-Run gasoline (HSR)/naphtha splitter column where HSR is separated from naphtha. The naphtha stream is sent to storage for reformer feed. The stabilized HSR is pumped from the HSR/naphtha splitter to the Merox treater for sweetening. In this process, the HSR is contacted with Merox reagent (caustic solution containing Merox catalyst), which converts mercaptans to disulfides. The treated HSR stream is then sent to storage.

The overhead streams from the two stabilizers contain butanes and propane recovered from the feed. The combined overhead streams feed the SGP depropanizer column, which separates propane and butane by distillation. The propane goes overhead and is sent to amine treating. The depropanizer bottom stream, which contains mostly butane, is either sold or sent to the Butamer unit. No additional treatment of the butanes is required.

All of the SGP light feeds are processed in the absorber and stripping columns. These two columns remove propane and butane from light feedstock streams coming from other refinery process units. In the absorber column, a portion of the stabilized LSR stream from one of the two stabilizers is used as lean oil. Lean oil (lean in propane and butane) has the capacity to preferentially absorb propane and butane components from other streams. Lean oil, fed to the top of the absorber, is enriched by the absorption of propane and butane contained in the light gas

stream fed to the bottom of the column. The lighter components, methane and ethane, are not absorbed as readily in the lean oil and are removed overhead, sent to one of the refinery fuel gas amine contactors to remove H_2S, and then sent to the refinery fuel gas system.

Rich oil (enriched with propane and butane) from the bottom of the absorber is stripped of lighter components in the stripper column. The stripper overhead stream flows back to the absorber column. Rich oil from the stripper column is pumped back to the stabilization section of the SGP for removal of the propane and butane to complete the lean oil/rich oil cycle.

Essentially all the H_2S in the SGP feed is collected in the propane product stream. In order to make the propane marketable, it is contacted with a methyldiethanolamine (MDEA) solution in parallel amine contactor columns. Sweetened propane leaves the bottom of the amine contactor column. Rich amine is returned to the amine plant for regeneration. The sweetened propane is further treated by caustic and water washes and then flows to a dehydration unit prior to being sent to sales.

The SGP project will install new, high-capacity distillation trays in the depropanizer column in order to improve fractionation between the propane and butane product streams. The project will also install a new jumper line to enable absorber column lean oil to be taken from either of the two stabilizer columns. None of the modifications will result in increased emissions from the SGP.

Saturated Gas Plant Fire Rebuild

On August 1, 2003, the Oklahoma Department of Environmental Quality (ODEQ) and ConocoPhillips agreed to Consent Order No. 03-254 (Order) to resolve issues of temporary construction, repair, and replacement at the refinery. The Order was necessary due to a hydrocarbon release and fire that occurred on July 21, 2003.

Paragraph 11 of the Order authorized ConocoPhillips to "construct and operate temporary jumper piping to facilitate continued sustainable operation of undamaged equipment and safe startup of damaged equipment at the [refinery] for 180 days from the effective date of [the] Order." Paragraph 12 of the Order authorized ConocoPhillips to "conduct repairs and 'like kind' replacements of components at the West Plant of the [refinery] damaged by the events of July 21, 2003." Paragraph 13 of the Order required ConocoPhillips to submit a permit modification for any of the changes made per Paragraphs 11 and 12 that meet the definition of modification. Two of the changes made per Paragraphs 11 and 12 were identified as meeting the definition of modification.

The first change is the addition of jumper piping to route No. 2 Catalytic Reforming Unit (CRU) stabilizer tower overhead liquid to the HF Alkylation Unit (Alky) de-ethanizer tower. The new line will allow the liquid propane-butane product stream (P-B) from the No. 2 CRU to be sent to the Alky in the event that the SGP absorber tower and/or stripper tower are removed from service. As a result, the No. 2 CRU will be able to operate independent of the SGP.

The second change is the addition of jumper piping to route No. 2 Cryogenic Unit (Cryo) P-B to the South Plant. The new line will allow the liquid P-B product stream from the No. 2 Cryo to be sent to the No. 5 FCC Vapor Recovery Unit in the event that the SGP absorber tower and/or stripper tower are removed from service. As with the first jumper piping mentioned above, this change will allow the No. 2 Cryo to operate independent of the SGP. Neither of these two jumper line changes will result in increased emissions from the refinery.

No. 2 Crude Topping Unit

The No. 2 Crude Topping Unit (No. 2 CTU) is one of three parallel crude units in the refinery that process raw crude oil. Crude topping units are the first major refinery processes that process the raw crude oil. The No. 2 CTU fractionates crude oil into several different boiling-range fractions, which are then sent to downstream units for further processing.

The No. 2 CTU is made up of four basic sections: the Preheat Train/Desalter section, the Preflash Distillation section, the Atmospheric Distillation section, and the Vacuum Distillation section.

Heat exchangers preheat the raw crude oil from storage temperature to the operating temperature of the desalter. The desalter removes metallic salts, water, and other impurities to prevent fouling of exchangers, coke formation in the furnaces, and equipment corrosion. The remainder of the heat exchanger train heats the desalted crude to the operating temperature of the Preflash Distillation tower.

The Preflash Distillation tower separates the light straight run (LSR) gasoline and preflash naphtha fractions from the crude oil charge before it is sent to the Atmospheric Distillation section. The Atmospheric Distillation tower separates the atmospheric naphtha, kerosene, hot oil distillate (HOD), and atmospheric gas oil (AGO) fractions from the heated feed. The Vacuum Distillation section uses sub-atmospheric pressures to separate the remaining heavy hydrocarbons and produce light vacuum gas oil (LVGO), heavy vacuum gas oil (HVGO), and resid in the Vacuum Distillation tower.

The No. 2 CTU project will replace vessels, including the preflash tower overhead drum, the atmospheric tower overhead drum, and the atmospheric tower side stripper, which have reached the end of their useful life and must be replaced for mechanical integrity reasons. The replacement vessels will be designed to meet current and future operational requirements. The project will also replace or modify heat exchangers in the crude preheat train in order to reduce fouling and increase run length.

Modifications planned for the No. 2 CTU atmospheric crude tower include modification of distillation trays in the AGO wash section and de-superheating of stripping steam to improve fractionation.

Modifications planned for the No. 2 CTU vacuum tower include installation of a new tray and pumps, piping, and instrumentation needed to collect HVGO dirty wash oil and recycle it back to the crude vacuum furnace. This project will also modify existing fractionation trays in the

vacuum tower LVGO section along with installation of a new heat exchanger to improve fractionation.

In addition to the specific items mentioned above, peripheral equipment such as, but not limited to, pumps, fuel gas filters, inlet/outlet piping, transfer lines, drums, heat exchangers, air coolers, control valves and other instrumentation, and utilities (e.g. electrical, steam, air systems, etc.) may be upgraded or added. General hydraulic debottlenecking will occur as a result of these modifications. After these modifications, the No. 2 CTU will be able to process "price advantaged" crude oils.

No. 2 CTU heaters H-6014 and H-6015 will be modified to include $ULNO_X$ burners to comply with the Consent Decree. NO_X emissions decreases resulting from the $ULNO_X$ burners are not creditable for PSD netting. However, these decreases are accounted for in the air quality modeling.

No. 4 Fluid Catalytic Cracker Unit

A fluidized catalytic cracking unit (FCCU) converts gas oil (which boils at 650°F to 1050°F) to gasoline, diesel fuels, and lighter hydrocarbon products, including refinery fuel gas (RFG) and propane/propylene-butane/butylene (PP-BB) liquid. The gas oil is contacted with a fine powdery catalyst in the riser of the converter vessel at temperatures in excess of 900°F to "crack" the heavy, high boiling-range gas oil into lighter gasoline and diesel fuel products.

Catalyst is separated from the cracked petroleum products in the reactor/disengager portion of the converter vessel. The catalyst is stripped with steam to remove hydrocarbon clinging to the surface of the particles and then transferred to the regenerator portion of the converter vessel where coke material, which is produced during the cracking reactions, is burned with air, provided by the regenerator air blower, in a continuous process that produces a stream of flue gas. The regenerated catalyst is then contacted with more gas oil and sent back to the riser/reactor. Catalyst carried with the flue gas from the regenerator is separated from the gas by internal cyclones (99.998% efficiency). A small amount of catalyst is eventually broken down in the high temperature regenerator environment to a size small enough to pass through the cyclone separators and out the stack.

The regenerator flue gas is cooled in a waste heat boiler that recovers heat to produce steam that is used by other refinery units. The No. 4 FCCU waste heat boiler is a simple shell-and-tube heat exchanger and is not gas fired. The cooled flue gas is discharged to the atmosphere from the No. 4 FCCU stack. Small catalyst particles in the flue gas are the primary source of PM emissions from the stack and cause visible opacity.

Located immediately downstream of the FCCU converter is the product fractionation process unit, which consists of three sections: Heavy Product Fractionation, Gas Recovery Plant, and Light Product Fractionation.

The purpose of the main fractionation column of the Heavy Product Fractionation section is to quench the FCC disengager overhead vapor and separate the unreacted heavier liquid fractions from the total stream. This results in the recovery of light cycle oil (LCO), which will be sent to the new No. 9 HDT for sulfur removal/reduction; naphtha, which is sent to gasoline blending; and bottoms slurry, which is fed to the Coker unit or sold. The remaining light liquids and gases are further separated in the Vapor Recovery Unit (VRU), which is made up of the Gas Recovery Plant and the Light Product Fractionation section.

The Gas Recovery Plant takes the gas from the Heavy Product Fractionation section, chills it with SUVA refrigeration and separates the non-condensable and condensable hydrocarbons. This results in the recovery of valuable light liquid products that go to the Light Product Fractionation section for further separation. The gases are amine treated and sent to the refinery fuel gas system.

In the Light Product Fractionation section, the FCC gasoline stream is stabilized by the removal of the condensable P-B hydrocarbons. The gasoline is sent to the Refinery Clean Fuels facility for sulfur removal/reduction and the P-B liquid is sent to the No. 5 FCCU VRU for further processing.

The No. 4 FCCU project will include replacement of the converter riser feed nozzles and installation of piping and instrumentation necessary to provide an LCO quench for the riser cyclones. The main purpose of the cyclone quench is to reduce generation of excess gases in the disengager vessel resulting from over-cracking of higher-value products. Installation of new riser feed nozzles is for the purpose of improving mechanical reliability.

Modifications planned for the No. 4 FCCU main fractionator include replacement of the distillation trays in the LCO section of the tower with packing to improve separation of the diesel oil fraction from the bottoms slurry. A new heat exchanger will also be installed to improve control of heat removal for the main fractionator LCO section, which will also improve diesel oil recovery. Finally, a larger overhead vapor nozzle will be installed on the main fractionator tower to allow more light liquids and gases to flow from the column to the VRU section for recovery of light products.

Modifications planned for the VRU section of the No. 4 FCCU are replacement of the distillation trays in the absorber-stripper column and secondary absorber column with packing in order to improve ethane removal from the P-B product stream.

In addition to the specific items mentioned above, peripheral equipment such as, but not limited to, pumps, filters, inlet/outlet piping, transfer lines, drums, heat exchangers, air coolers, control valves and other instrumentation, and utilities (e.g. electrical, steam, air systems, etc.) may be upgraded or added. General hydraulic debottlenecking will occur as a result of these modifications.

Per the Consent Decree, the No. 4 FCCU is required to use low-NO_X combustion promoter and NO_X and SO_X reducing additives to reduce NO_X and SO_2 emissions from the regenerator. NO_X

and SO_X emissions decreases resulting from use of these additives are not creditable for PSD netting. However, these decreases are accounted for in the air quality modeling.

No. 3 Catalytic Reformer

The No. 3 Catalytic Reforming Unit (No. 3 CRU) converts low-octane Light Straight Run Naphtha (LSRN) from the No. 1, 2, and 4 Crude Topping Units (CTUs), the No. 2 CTU Preflash Tower, and the LSRN Splitter W-42, into high-octane reformate. Reforming enables production of high-octane gasoline without octane-enhancing additives such as lead. The hydrodesulfurization (HDS) section of the No. 3 CRU removes sulfur-containing compounds by hydrogenation. Removal of sulfur compounds is necessary in order to extend the active life of the reforming catalyst and to meet gasoline sulfur specifications. The No. 3 CRU contains three major operating sections: hydrodesulfurization, reforming reaction, and fractionation.

The hydrodesulfurization (HDS) section uses hydrogen produced in the reforming reaction section or from the refinery hydrogen network (during startup) to convert (hydrogenate) sulfur compounds in the LSRN to H_2S. The products from this section are hydrotreated LSRN, which goes to the reforming section, and sour fuel gas. Nitrogen, oxygen, and chlorine compounds are also converted to more manageable compounds.

The reforming reaction section takes the hydrotreated LSRN from the HDS section as feed to a series of fired heaters and reforming reactors. The reactors convert the low-octane components to high-octane components. Products from this section are hydrogen and unstabilized reformate. Hydrogen is sent to the HDS section and any excess is exported to the refinery hydrogen network. The unstabilized reformate is fed to the fractionation section.

The fractionation section, made up of a debutanizer column and related equipment, receives feed from the reforming section. Butane and lighter hydrocarbons are separated from the unstabilized reformate and sent to the Saturated Gas Plant for further processing. The stabilized reformate product, including pentane and heavier hydrocarbons, is sent to tankage for gasoline blending.

The No. 3 CRU project will reduce emissions from and improve the mechanical integrity of the reformer main furnace, H-6007, by either replacement of the heater or modification of the existing equipment including replacement of tubes and refractory, possible reconfiguration of tube passes, and possible installation of reconfigured convection sections. In either case, the new or modified furnace will be equipped with $ULNO_X$ burners to comply with the Consent Decree. NO_X emissions decreases resulting from installation of $ULNO_X$ burners, or shutdown of the existing furnace, are not creditable for PSD netting. However, these decreases are accounted for in the air quality modeling.

Modification of the No. 3 CRU heater H-6007, including replacement of tubes and refractory, possible reconfiguration of tube passes, and possible installation of reconfigured convection sections as well as installation of $ULNO_X$ burners, was originally included in construction permit No. 2001-305-C (No. 3 Catalytic Reformer Expansion). However, the modifications were never made; therefore, replacement or modification of H-6007 is included in this permit.

No. 5 Fluid Catalytic Cracker Unit

The No. 5 FCCU converter is similar to that of the No. 4 FCCU except that it includes a gas-fired CO boiler, B-5004, instead of a shell-and-tube heat exchanger. B-5004 is a tubed boiler that produces steam by recovery of heat from the regenerator flue gas and is fired with RFG for supplemental heat.

Like the No. 4 FCCU, the No. 5 FCCU includes a main fractionator tower, which is used to quench the FCCU disengager overhead vapor and separate the unreacted heavier liquid fractions from the total stream. This results in the recovery of LCO, which will be sent to the new No. 9 HDT for sulfur removal/reduction; naphtha, which is sent to gasoline blending; and bottoms slurry, which is sold. The remaining light liquids and gases are further separated in the Vapor Recovery Unit (VRU), which is made up of the Gas Recovery Plant, the No. 1 Cryogenic Unit, and the Light Product Fractionation section.

The Gas Recovery Plant takes gas from the Heavy Product Fractionation section and wet gas from the Coker unit and separates the non-condensable and condensable hydrocarbons. This results in the recovery of valuable light liquid products that go to the Light Product Fractionation section for further separation. The gas is amine treated and sent to the No. 1 Cryogenic Unit, which recovers additional light liquid products and sends the remaining gas to the refinery fuel gas system.

In the Light Product Fractionation section, the FCCU gasoline stream is stabilized by the removal of the condensable propane/propylene-butane/butylene (PP-BB) hydrocarbons. The gasoline is sent to the refinery Clean Fuels Facility for sulfur removal/reduction, and the PP-BB liquid is combined with No. 4 FCCU PP-BB liquid and sent to the depropanizer column for separation into propane-propylene liquid (PP) and butane-butylene liquid (BB). The PP liquid is amine treated and sent to either the Catalytic Polymerization Unit (Cat Poly), and/or to the HF Alkylation Unit (Alky), and/or to sales. The BB liquid is sent to the Alky for further processing.

The No. 5 FCCU project will include replacement of the converter “J” bend riser with a “Y” bend riser, installation of new or relocation of existing riser feed nozzles, installation of piping and instrumentation necessary to provide an LCO quench for the riser cyclones, and installation of new internals in the converter catalyst stripper. The main purpose of the new riser and feed nozzles is to improve mechanical reliability. The cyclone quench is intended to reduce generation of excess gases in the disengager vessel resulting from over-cracking of higher-value products. The main purpose of the new internals in the catalyst stripper is to improve catalyst stripping efficiency and reduce steam usage. The No. 5 FCCU modification project will also replace or modify process equipment including, but not limited to, vessels, heat exchangers, air blower, CO boiler, pumps, control valves, piping, instrumentation, and other process equipment in order to increase the unit’s gas oil feed capacity and/or improve product yields. Also, a new 4,200-gpm cell will be added to the South Plant cooling tower, which provides cooling water to the No. 5 FCCU. In addition, cooling water pumps and piping will be modified to improve cooling water circulation.

No. 5 FCCU feed heater H-5001 will be modified to include $ULNO_X$ burners to comply with the Consent Decree. The Consent Decree also requires the use of low-NO_X combustion promoter and NO_X reducing additive as well as installation of a Selective Non-Catalytic Reduction (SNCR) unit in CO boiler B-5004 to reduce NO_X emissions from the regenerator. A wet gas scrubber (WGS) will be installed in order to reduce the regenerator flue gas SO_2 concentration to the Consent Decree limits of 25 ppmdv @ 0% oxygen (365-day rolling average) and 50 ppmdv @ 0% oxygen (7-day rolling average) and to meet the NSPS Subpart J requirement for PM_{10} control (1 lb/1000 lbs of coke burned). The PM_{10} control limit is also a requirement of NESHAP Subpart UUU (MACT II). Emissions decreases resulting from the $ULNO_X$ burners, NO_X reducing additive, SNCR, and WGS are not creditable for PSD netting. However, these decreases are accounted for in the air quality modeling.

HF Alkylation Unit

The HF Alkylation Unit (Alky) uses hydrogen fluoride (HF) as a catalyst to promote the reaction of olefin with isobutane to form high-octane gasoline blending components. The olefin feed stream to the unit is produced in the fluid catalytic cracking and delayed coking processes. As mentioned in the No. 5 FCCU process description, the olefin feed is split into a propane-propylene stream (PP) and a butane-butylene stream (BB). The BB stream is treated for H_2S in the Alky Unit BB Merox Treater prior to feeding the Selective Hydrogenation Process unit (SHP) to remove butadiene and to isomerize 1-butene. The PP stream can be processed through the Catalytic Polymerization Unit before going to the Alkyl. Isobutane makeup feed is either produced in the Butamer Unit or purchased from outside the refinery.

The Alky yields a high-octane gasoline component (alkylate), butane, and propane. The alkylate splitter can also produce an aviation gasoline base component by distilling the higher-octane portion, which is the lightest 60%-90% of the alkylate stream. There is also a small light ends stream that goes to the refinery fuel gas system.

The Alky is made up of six main sections: the Deethanizer section, the Merox Treating section, the Reactor Feed and HF Circulation section, the Fractionation section, the Propane and Butane Treating section, and the Neutralization section.

The Deethanizer section removes methane, ethane, and most of the H_2S from the PP and cavern charge to the Alkylation Unit. The Deethanizer system consists of a feed surge drum, pumps, a feed/bottoms exchanger, the deethanizer tower with overhead condenser, a reflux drum, a steam heated reboiler, and a bottoms cooler.

The Merox process of the Universal Oil Products Company (UOP) is a chemical treatment for petroleum distillates that removes mercaptans by conversion to byproduct disulfides. First, a mild caustic reacts with H_2S in prewash drums before subsequent contact with a stronger caustic solution in the extractor tower, which extracts mercaptan compounds from the PP and BB streams. The mercaptans in the caustic streams are combined and converted to disulfides in the common Merox unit consisting of one oxidizer drum, disulfide separator, alkylate-caustic separator, and associated pumps and heat exchangers.

In the Reactor Feed and HF Circulation section of the unit, the makeup isobutane and the olefin feed are dried and combined with the recycle isobutane before entering the reactor legs. The reactor products are separated, the HF is recycled and cooled, and a slip stream of HF is regenerated. This section consists of a cavern wash drum, feed sphere, feed driers, reactor/settler vessel, acid coolers, acid rerun column, acid soluble oil (ASO) neutralizer, and associated pumps and exchangers.

In the Fractionation section, the depropanizer separates the hydrocarbon feed from the acid settler into HF acid and propane as the overhead product; isobutane as a side draw product for recycle; and alkylate as a bottoms product.

The depropanizer has a pumped reboiler circuit that includes the three parallel, gas-fired reboilers, H-0057, H-0058, and H-0059. These three furnaces have a common air preheat system to increase the furnace efficiency and thus reduce fuel consumption. This is accomplished by preheating the combustion air through a rotating heat exchanger which alternately contacts the cool air and hot flue gas. A forced draft fan pushes air through the preheater to the furnaces, and an induced draft fan pulls flue gas from the preheater and pushes it to the flue stack.

The debutanizer separates normal butane from alkylate thus reducing the alkylate vapor pressure. The debutanizer has a thermosiphon reboiler heated with 175-psig steam.

Light alkylate for aviation gasoline blending is produced in the alkylate splitter. Feed to the alkylate splitter is a portion of the debutanizer bottoms stream. The Av-Gas tower has a thermosiphon reboiler heated with 175-psig steam.

The Propane and Butane Treating section uses defluorinators to lower the fluoride content of the product. The propane treating system consists of defluorinators, a KOH treater, and three heat exchangers. The butane treating system consists of defluorinators, a KOH treater, and four heat exchangers.

In the Neutralization section, traces of HF are removed from gases relieved from process vessels and equipment. These gases pass through the Acid Relief Neutralizer before entering the main flare header. The neutralizer contains a solution of 45 percent potassium hydroxide (KOH) when freshly added to the system. The KOH neutralizes the HF contained in the relief gases from the acid section of the Alky Unit. Without neutralization, HF would cause excessive corrosion in the carbon steel flare system downstream of the acid neutralizer.

The Alky will undergo an upgrade project during a unit turnaround in 2006. During the turnaround, there will be exchanger modifications/cleaning, piping modifications, pump impeller changes, and control valve changes. This project is needed to support the previously mentioned FCCU projects. The following is a general summary of planned major turnaround activities:

- Re-tray the deethanizer tower
- Replace the Merox oxidizer caustic heat exchanger
- Upgrade of the ASO separator

- Replace the Merox oxidizer tower
- Replacement of the Coker/Combo/Alky flare stack and tip – possible total replacement
- Cooling tower repair and upgrade including internals and nozzle replacements, pump modifications, and fan work
- Replace the acid relief neutralizer drum
- Relocation/reinstallation of MTBE debutanizer W-90 (decommissioned as part of the MTBE unit shutdown) to be used as a butane/pentane splitter
- Re-tray the depropanizer tower
- Re-tray the debutanizer tower

During the unit turnaround, depropanizer reboilers H-0057, H-0058, and H-0059 will be modified to include $ULNO_X$ burners to comply with the Consent Decree. Emissions decreases resulting from the $ULNO_X$ burners are not creditable for PSD netting. However, these decreases are accounted for in the air quality modeling.

East Plant Flare

This project will include implementation of equipment and/or instrumentation for the East Plant flare that support good air pollution control practices as approved by EPA. To this end, potential modifications to the flare include, but are not limited to, installation of a new flare gas recovery unit (FGRU), tie-in to an existing FGRU, installation of a Sulfur Sorber, and/or installation of H_2S CEMS instrumentation. The East Plant flare will also be equipped with flame detection instrumentation to ensure the continuous presence of a flame.

The emissions increases included in this permit application assume installation of a new FGRU because it is believed to be the worst-case scenario (i.e. greatest number of fugitive components). Because of Consent Decree requirements, emissions decreases are not creditable for PSD netting.

South Plant Flare

This project will include implementation of equipment and/or instrumentation for the South Plant flare that support good air pollution control practices as approved by EPA. To this end, potential modifications to the flare include, but are not limited to, installation of a new flare gas recovery unit (FGRU), tie-in to an existing FGRU, installation of a Sulfur Sorber, and/or installation of H_2S CEMS instrumentation. The South Plant flare will also be equipped with flame detection instrumentation to ensure the continuous presence of a flame.

The emissions increases included in this permit application assume installation of a new FGRU because it is believed to be the worst-case scenario (i.e. greatest number of fugitive components). Because of Consent Decree requirements, emissions decreases are not creditable for PSD netting.

West Plant Flare

The No. 9 HDT and Hydrogen Plant will be located in the Ponca City Refinery West Plant and will be tied into the flare stack that was installed as part of the refinery Gasoline Clean Fuels project. The new West Plant flare, which is equipped with a flare gas recovery unit (FGRU), was put into service on 10/23/2003 and the old West Plant flare was extinguished on 12/9/2003.

In addition to the Gasoline Clean Fuels units, the No. 1 CTU and the No. 4 CTU are tied into the West Plant flare. The combined crude charge rate of the two CTUs is currently, and will continue to be, until the requested permit is issued, administratively constrained by a safe operating limit (SOL) which is based on the estimated back pressure that would be imposed on the CTU pressure relief valves (PRVs) by the old West Plant flare during emergency over-pressure scenarios. The SOL established a "sliding scale" that limits/links the total crude charge rate of the two CTUs. Connecting the two CTUs to the new West Plant flare will enable the cancellation of the combined crude charge SOL, which will, in turn, allow the two CTUs to operate at their individual potentials. Because this change in method of operation will increase the combined potential of the two CTUs, cancellation of the SOL is included in this permit application. The following existing permits presently limit emissions from the No. 1 CTU and the No. 4 CTU:

- Permit No. 2002-115-C (M-1) – No. 4 CTU/CVU Expansion – Issued 10/28/2003
- Permit No. 2002-476-C (PSD) – No. 1 Crude Topping Unit Upgrade –Issued 3/31/2004.

SECTION IV. PROJECT EMISSIONS

The Ponca City Refinery is an existing PSD major source. This section presents the emission calculation methodology used to determine PSD applicability for the new, modified, and associated units, including process heaters, FCCUs, equipment leaks, cooling towers, a storage tank, and emissions associated with increased steam production.

A PSD Netting analysis was performed based on suggested emissions netting procedures in the Draft Environmental Protection Agency (U.S. EPA) New Source Review (NSR) Workshop Manual. A six-step procedure was used for determining the net emissions change:

1. Emissions Increases from the Project (PSD Applicability) - Determine the emission increases from the project from any new sources, modified sources, and associated sources (i.e. debottlenecked units). If increases 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. Emissions 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. This step also includes any emissions decreases from the project.

4. Creditable Emissions Changes - Determine which contemporaneous emissions changes are creditable.
5. Amount of Emissions Increase and Decrease - Determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease.
6. PSD Review Applicability - 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.

The following sections detail each of the steps outlined above.

Step 1. Emissions Increases from the Project (PSD Applicability)

The maximum potential emissions from each new, modified, and associated source was determined for this project. For each PSD pollutant, the actual emissions are subtracted from the potential emissions to determine the emissions increase for each new, modified, or associated source. Actual emissions are defined in OAC 252:100-31 as "the average rate in tons per year at which the unit actually emitted the pollutant during a two year period which precedes the particular date and which is representative of normal source operation." For new emissions sources the actual emissions are zero. For this project, ConocoPhillips averaged emissions from the 2001 and 2002 emission inventories to determine actual emissions for each pollutant from a given source. Emission decreases are not considered in this step. The emissions increases for each new, modified, and associated source are shown in the following sections.

Process Heaters and Boilers

1. Emissions Increases Used for both PSD Applicability and PSD Netting

The proposed ULSD project will include three new gas-fired process heaters (H-1001, H-9901, and H-9902) and the H_2 plant associated with the ULSD unit will include a new gas-fired reformer heater (ULSD-5/5a). Design of the H_2 plant reformer heater will allow the exhaust gases to pass though a single stack.

Two gas-fired, mechanical draft boilers (B-0009 and B-0010) are proposed for construction as part of this permit application. The boilers are necessary to replace the steam production capacity that will be lost due to the shutdown of the two Cogeneration Units located at the refinery. The Cogeneration Units will be shutdown during the first half of 2006.

No. 3 CRU reformer main furnace H-6007 will be either replaced or modified as part of this permit. In either case, the new or modified furnace will be equipped with $ULNO_X$ burners to comply with the Consent Decree. NO_X emissions decreases resulting from either installation of $ULNO_X$ burners or shutdown of the existing furnace are not creditable for PSD netting. However, these decreases are accounted for in the air quality modeling. For PSD applicability and netting purposes, construction of a new heater (NH-6007) will be assumed with the

corresponding new emissions accounted for. Shutdown of the existing heater (H-6007) will provide corresponding creditable emissions reductions for all pollutants except NO_X.
Gas-fired heaters that will be modified as part of this permit application include No. 2 CTU heaters H-6014 and H-6015; No. 5 FCCU feed preheater H-5001; and Alky depropanizer reboilers H-0057, H-0058, and H-0059. The existing burners in these heaters and boilers will be replaced with increased capacity $ULNO_X$ burners that are fired with refinery fuel gas. These modifications are required for compliance with the Consent Decree. Emissions decreases resulting from installation of the $ULNO_X$ burners are not creditable for PSD netting purposes. However, the decreases are accounted for in the air quality modeling.

Associated emissions increases for process heaters are included in this permit application for the purpose of verifying PSD applicability and air quality modeling. No. 1 CTU heaters H-0001, H-0005, and H-0016, and No. 4 CTU charge heaters H-0003 and H-0004 are included as associated heaters as a result of the change in method of operation as described in the West Plant Flare process description section of Section III. The project does not involve physical modifications to any associated emission units. These emission units will continue to operate in compliance with currently applicable rules, regulations, and permit conditions. Therefore, this permit does not include emission limits, or specific conditions for the associated emission units.

Table IV-1 shows the potential emission calculations for new, modified, and associated process heaters and boilers. Net emissions increases (potential emissions less past actual emissions) are shown for each criteria pollutant. The future firing rates (MMBtu/hr) of the associated heaters are based on predicted future heating requirements.

Except as noted in Table IV-1, criteria pollutant emissions factors for the gas-fired heaters and boilers are derived as described in this paragraph. Emissions factors for VOC and PM_{10} are based on AP-42 (7/98) Table 1.4-2. Emission factors for CO are 0.04 lb/MMBtu per requirements of the Consent Decree. Emission factors for NO_X are based on vendor guarantees for the $ULNO_X$ burners. Emission factors for SO_2 are based on the NSPS Subpart J-allowable H_2S content of 0.10 grains per dry standard cubic foot (grains/dscf) (160 parts per million on a volumetric basis [ppmv]). All emissions are based on continuous operation and a refinery fuel gas with a higher heating value (HHV) of 700 Btu/Scf.

Table IV-1. Emissions Increases for Process Heaters & Boilers

Emission Unit	Max Heat Rate, MMBtu/hr (HHV)	Pollutant	Emission Factor, lb/MMBtu (HHV)	Potential Emissions		Actual Emissions	Net Emissions
				lb/hr	TPY	TPY	TPY
New Heater H-1001 Heater for #4 HDT	30.0	NO_X	0.0500	1.50	6.60	0.0	**6.6**
		SO_2	0.0410	1.23	5.39	0.0	**5.4**
		CO	0.0400	1.20	5.26	0.0	**5.3**
		VOC	0.0054	0.16	0.71	0.0	**0.7**
		PM_{10}	0.0075	0.23	1.0	0.0	**1.0**
New Heater H-9901 Heater for #9 HTD	40.0	NO_X	0.0500	2.00	8.76	0.0	**8.8**
		SO_2	0.0410	1.64	7.18	0.0	**7.2**
		CO	0.0400	1.60	7.01	0.0	**7.0**
		VOC	0.0054	0.22	0.96	0.0	**1.0**
		PM_{10}	0.0075	0.30	1.3	0.0	**1.3**
New Heater H-9902 Heater for Stripper Reboiler	50.0	NO_X	0.0500	2.50	11.0	0.0	**11.0**
		SO_2	0.0410	2.05	8.98	0.0	**9.0**
		CO	0.0400	2.00	8.76	0.0	**8.8**
		VOC	0.0054	0.27	1.2	0.0	**1.2**
		PM_{10}	0.0075	0.37	1.6	0.0	**1.6**
New Heater ULSD-5/5a Steam-Methane Reformer Furnace	282	NO_X	0.0750 [1]	21.2	92.8	0.0	**92.8**
		SO_2	0.0410	11.6	50.8	0.0	**50.8**
		CO	0.0400	11.3	49.5	0.0	**49.5**
		VOC	0.0054	1.52	6.66	0.0	**6.7**
		PM_{10}	0.0075	2.12	9.28	0.0	**9.3**
New Heater NH-6007 No. 3 CRU Main Reactor Furnace	175	NO_X	0.0500	8.75	38.3	0.0	**38.3**
		SO_2	0.0410	7.18	31.4	0.0	**31.4**
		CO	0.0400	7.00	30.7	0.0	**30.7**
		VOC	0.0054	0.94	4.12	0.0	**4.1**
		PM_{10}	0.0075	1.31	5.74	0.0	**5.7**
New Boilers B-0009/B-0010 Steam Generating Boilers	734	NO_X	0.0500	36.7	161	0.0	**161**
		SO_2	0.0410	30.1	132	0.0	**132**
		CO	0.0400	29.4	129	0.0	**129**
		VOC	0.0054	3.96	17.3	0.0	**17.3**
		PM_{10}	0.0075	5.51	24.1	0.0	**24.1**
Modified Heater H-6014 No. 2 CTU Heater	71.0	NO_X	0.0500	3.55	15.5	18.7	**-3.2**
		SO_2	0.0410	2.91	12.8	0.4	**12.4**
		CO	0.0400	2.84	12.4	15.7	**-3.3**
		VOC	0.0054	0.38	1.7	1.0	**0.7**
		PM_{10}	0.0075	0.53	2.3	1.4	**0.9**
Modified Heater H-6015 No. 2 CTU Heater	130	NO_X	0.0500	6.50	28.5	57.2	**-28.7**
		SO_2	0.0410	5.33	23.3	0.6	**22.7**
		CO	0.0400	5.20	22.8	23.5	**-0.7**

Emission Unit	Max Heat Rate, MMBtu/hr (HHV)	Pollutant	Emission Factor, lb/MMBtu (HHV)	Potential Emissions		Actual Emissions	Net Emissions
				lb/hr	TPY	TPY	TPY
		VOC	0.0054	0.70	3.1	1.5	**1.6**
		PM_{10}	0.0075	0.98	4.3	2.1	**2.2**
Modified Heater H-5001 No. 5 FCCU Feed Preheater	104	NO_X	0.0500	5.20	22.8	47.4	**-24.6**
		SO_2	0.0410	4.26	18.7	0.5	**18.2**
		CO	0.0400	4.16	18.2	16.3	**1.9**
		VOC	0.0054	0.56	2.5	1.1	**1.4**
		PM_{10}	0.0075	0.78	3.4	1.4	**2.0**
Modified Heater H-0057 Alky Depropanizer Heater	70.0	NO_X	0.0500	3.50	15.3	15.3	**0.0**
		SO_2	0.0410	2.87	12.6	1.5	**11.1**
		CO	0.0400	2.80	12.3	16.8	**-4.5**
		VOC	0.0054	0.38	1.7	1.1	**0.6**
		PM_{10}	0.0075	0.53	2.3	1.5	**0.8**
Modified Heater H-0058 Alky Depropanizer Heater	49.0	NO_X	0.0500	2.45	10.7	10.7	**0.0**
		SO_2	0.0410	2.01	8.8	1.1	**7.7**
		CO	0.0400	1.96	8.6	11.9	**-3.3**
		VOC	0.0054	0.26	1.2	0.8	**0.4**
		PM_{10}	0.0075	0.37	1.6	1.1	**0.5**
Modified Heater H-0059 Alky Depropanizer Heater	70.0	NO_X	0.0500	3.50	15.3	15.4	**-0.1**
		SO_2	0.0410	2.87	12.6	1.5	**11.1**
		CO	0.0400	2.80	12.3	16.9	**-4.6**
		VOC	0.0054	0.38	1.7	1.1	**0.6**
		PM_{10}	0.0075	0.53	2.3	1.5	**0.8**
Associated Heater H-6151 No. 4 FCCU Preheater	80.0	NO_X	0.0980 [2]	7.84	34.3	16.5	**17.8**
		SO_2	0.0410	3.28	14.4	0.4	**14.0**
		CO	0.0824 [2]	6.59	28.9	13.9	**15.0**
		VOC	0.0054	0.43	1.9	0.9	**1.0**
		PM_{10}	0.0075	0.60	2.6	1.3	**1.3**
Associated Heater H-0003 No. 4 FCCU Heater	25.0 [3]	NO_X	0.1000	-	10.8	8.0	**2.8**
		SO_2	0.0410	-	4.38	1.2	**3.2**
		CO	0.0390	-	4.27	6.6	**-2.3**
		VOC	0.0054	0.14	0.61	0.4	**0.2**
		PM_{10}	0.0075	0.19	0.80	0.6	**0.2**
Associated Heater H-0004 No. 4 FCCU Heater	109 [3]	NO_X	0.1500	16.4	71.6	74.6	**-3.0**
		SO_2	0.0410	4.47	19.1	4.8	**14.3**
		CO	0.0390	4.36	18.6	28.6	**-10.0**
		VOC	0.0054	0.59	2.6	1.9	**0.7**
		PM_{10}	0.0075	0.82	3.6	2.6	**1.0**
Associated Heater H-6005 No. 2 CTU Preflash Tower Reboiler	157.0 [4]	NO_X	0.0750	11.8	51.6	12.1	**39.5**
		SO_2	0.0380	6.04	26.4	1.4	**25.0**
		CO	0.0820	12.9	56.4	53.3	**3.1**
		VOC	0.0050	0.79	3.5	2.7	**0.8**
		PM_{10}	0.0070	1.1	4.8	3.5	**1.3**

1. Phone conversation with Joel Wilson, process engineer for the ULSD project.
2. Based on AP-42 (7/98) Table 1.4-1.

3. Heater duty, emission factors, and TPY emissions based on Permit No. 2002-115-C (M-1) – No. 4 CTU/CVU Expansion. NO_x emission factor based on heater stack tests plus safety factor. TPY limit may not correspond to lb/hr rate.
4. Heater duty, emission factors, and TPY emissions based on Permit No. 97-286-O (M-1) - Replacement of H-6006 with H-6005.

2. Emissions Increases Used for PSD Applicability Only.

Increases in associated emissions from the following process heaters were considered for PSD applicability only and not considered in the PSD emissions netting analysis. This is because a previous PSD permit, 2002-476-C (PSD) - No. 1 CTU Upgrade Project, estimated emissions for H-0001, H-0005, H-0010, H-0011, H-0016, H-0023, H-0028, H-0029, H-0046, H-0048, H-6012, H-6013, and H-7501 at their corresponding maximum capacity. The parameters used for these heaters in the No. 1 CTU Upgrade PSD project were estimated based on the forecasted increase in demand for future projects. Since these heaters will not be fired at a higher rate, they are not considered associated sources for this PSD project also. If these sources were considered associated for PSD netting purposes for this project, then their emissions would, essentially, be double counted for the two PSD projects.

Table IV-2 shows the potential emission calculations for these associated process heaters. Emission increases (potential emissions less actual emissions) are shown for each criteria pollutant. All the emissions information for these heaters is derived from Permit No. 2002-476-C (PSD) - No. 1 Crude Topping Unit Upgrade, which was issued on March 31, 2004.

Emissions of PM_{10} and VOC are based on emission factors for natural gas combustion from AP-42 (7/98) Table 1.4-2. Emissions of CO are based on an emission factor of 0.0824 lb/MMBtu from AP-42 (7/98) Table 1.4-1, or from the Consent Decree limit of 0.04 lb/MMBtu. Emissions of NO_X are based on an emissions factor of 0.0980 lb/MMBtu from AP-42 (7/98) Table 1.4-1, or on specific emission factors for each heater per Permit No. 2002-476-C (PSD). Emission factors for SO_2 are based on the NSPS Subpart J-allowable H_2S content of 0.10 grains per dry standard cubic foot (grains/dscf) (160 parts per million on a volumetric basis [ppmv]) or on specific emission factors for each heater per Permit No. 2002-476-C (PSD). All emissions are based on continuous operation and a refinery fuel gas with a higher heating value (HHV) of 700 Btu/Scf.

Table IV-2. Emissions Increases for Associated Process Heaters (for PSD Significance Level Analysis Only)

Emission Unit	Max Heat Rate, MMBtu/hr (HHV)	Pollutant	Emission Factor, lb/MMBtu (HHV)	Potential Emissions		Actual Emissions	Net Emissions
				lb/hr	TPY	TPY	TPY
Associated Heater H-0001 No. 1 CTU Crude Charge Heater	175	NO_X	0.0500	8.75	38.3	130	**-92**
		SO_2	0.0384	6.72	29.4	8.8	**20.6**
		CO	0.0400	7.00	30.7	53.6	**-22.9**
		VOC	0.0054	0.94	4.1	3.5	**0.6**
		PM_{10}	0.0075	1.30	5.7	4.8	**0.9**
Associated Heater H-0005 No. 1 CTU Crude Charge Heater	85.0	NO_X	0.0980	8.33	37.0	20.6	**16.4**
		SO_2	0.0410	3.49	16.0	2.9	**13.1**
		CO	0.0824	7.00	31.0	17.3	**13.7**
		VOC	0.0054	0.46	2.0	1.1	**0.9**
		PM_{10}	0.0075	0.63	3.0	1.6	**1.4**
Associated Heater H-0016 No. 1 CTU Vacuum Charge Heater	107	NO_X	0.0350	3.73	16.4	0.0	**16.4**
		SO_2	0.0384	4.10	18.0	0.0	**18.0**
		CO	0.0400	4.27	18.7	0.0	**18.7**
		VOC	0.0054	0.58	2.5	0.0	**2.5**
		PM_{10}	0.0075	0.80	3.5	0.0	**3.5**
Associated Heater H-0023 No. 5 HDT Charge Heater	52.4	NO_X	0.1370	7.18	31.4	8.8	**22.6**
		SO_2	0.0340	1.78	7.00	0.2	**6.8**
		CO	0.0824	4.32	18.9	7.4	**11.5**
		VOC	0.0054	0.28	1.2	0.5	**0.7**
		PM_{10}	0.0075	0.39	1.7	0.7	**1.0**
Associated Heater H-0028 No. 7 Coker Process Heater	129	NO_X	0.1370	17.7	78.0	46.4	**31.6**
		SO_2	0.0410	5.28	24.0	1.1	**22.9**
		CO	0.0824	10.6	47.0	35.3	**11.7**
		VOC	0.0054	0.70	3.0	2.3	**0.7**
		PM_{10}	0.0075	0.96	5.0	3.2	**1.8**
Associated Heater H-0029 No. 7 Coker Process Heater	75.0	NO_X	0.0980	7.35	32.2	18.4	**13.8**
		SO_2	0.0305	2.29	10.0	0.5	**9.5**
		CO	0.0824	6.18	27.1	17.3	**9.8**
		VOC	0.0054	0.40	1.8	1.1	**0.7**
		PM_{10}	0.0075	0.56	2.4	1.6	**0.8**
Associated Heater H-0046 No. 2 CRU Charge Heater	48.0	NO_X	0.0980	4.70	21.0	10.3	**10.7**
		SO_2	0.0410	1.97	9.0	0.2	**8.8**
		CO	0.0824	3.95	18.0	8.7	**9.3**
		VOC	0.0054	0.26	1.1	0.6	**0.5**
		PM_{10}	0.0075	0.36	2.0	0.8	**1.2**
Associated Heater H-0048 No. 2 CRU Reactor	241	NO_X	0.0350	8.45	37.0	104	**-67**
		SO_2	0.0384	9.27	43.4	1.3	**42.1**
		CO	0.0400	9.66	42.3	68.2	**-25.9**

Emission Unit	Max Heat Rate, MMBtu/hr (HHV)	Pollutant	Emission Factor, lb/MMBtu (HHV)	Potential Emissions		Actual Emissions	Net Emissions
				lb/hr	TPY	TPY	TPY
Preheater		VOC	0.0054	1.30	5.7	4.5	**1.2**
		PM_{10}	0.0075	1.8	7.9	6.2	**1.7**
Associated Heater H-6012 No. 3 CRU Desulfurizer Preheater	25.0	NO_X	0.0980	2.45	11.0	6.8	**4.2**
		SO_2	0.0410	1.03	5.0	0.1	**4.9**
		CO	0.0824	2.06	9.0	5.7	**3.3**
		VOC	0.0054	0.13	0.6	0.4	**0.2**
		PM_{10}	0.0075	0.19	1.0	0.5	**0.5**
Associated Heater H-6013 No. 3 CRU Desulfurizer Preheater	75.8	NO_X	0.0600	4.55	19.9	11.8	**8.1**
		SO_2	0.0380	2.88	12.6	0.3	**12.3**
		CO	0.0400	3.03	13.3	11.8	**1.5**
		VOC	0.0054	0.41	1.8	0.8	**1.0**
		PM_{10}	0.0075	0.56	2.5	1.1	**1.4**
Associated Heater H-0010 Sat Gas Plant Naphtha Reboiler	42.0	NO_X	0.0980	4.12	18.0	5.8	**12.2**
		SO_2	0.0410	1.72	7.5	0.7	**6.8**
		CO	0.0824	3.46	15.1	4.9	**10.2**
		VOC	0.0054	0.23	1.0	0.3	**0.7**
		PM_{10}	0.0075	0.31	1.4	0.5	**0.9**
Associated Heater H-0011 No. 7 HDT Heater	12.0	NO_X	0.1200	1.44	6.3	5.4	**0.9**
		SO_2	0.0410	0.49	2.3	0.3	**2.0**
		CO	0.0824	0.99	4.3	3.7	**0.6**
		VOC	0.0054	0.06	0.3	0.2	**0.1**
		PM_{10}	0.0075	0.09	0.4	0.3	**0.1**
Associated Heater H-7501 No. 6 HDT Heater	36.6	NO_X	-	-	18.0	6.6	**11.4**
		SO_2	-	-	5.3	0.2	**5.1**
		CO	0.0824	-	5.4	5.5	**-0.1**
		VOC	0.0054	0.20	0.6	0.4	**0.2**
		PM_{10}	0.0075	0.27	1.2	0.5	**0.7**

Cooling Towers

Modifications to two existing cooling towers are included in the proposed projects. The South Plant cooling tower (BLD-307CT) will receive a new cell (Cell 12) with a capacity of 4,200 GPM. The Alky cooling tower will be modified, by repairing the existing tower, but the capacity of the Alky cooling tower will not be increased; therefore, emissions from the Alky cooling tower will not be affected and the Alky cooling tower is not included in the emissions increase analysis. Emission calculations for total dissolved solids (TDS) concentration (850 parts per million [ppm]) and drift rate (0.002%) are based on current design information. Emissions for VOC are calculated using the controlled emission factor for petroleum refinery cooling towers presented in AP-42 (9/91) Table 5.1-2. Emission calculations are presented in Tables IV-3a and IV-3b.

TABLE IV-3A. COOLING TOWER PM_{10} EMISSIONS INCREASE

Emissions Unit	TDS, ppm	Drift Rate, %	Recirculation Rate, gpm	PM_{10}, lb/hr	PM_{10}, TPY	Past Actual, TPY	Net, TPY
BLD-307CT, Cell 12	850	0.002	4,200	0.04	0.2	0.0	**0.2**
Alky CT [1]	850	0.002	18,000	0.15	0.7	0.7	**0.0**

1. Alky cooling tower will be repaired with no increase in capacity.

TABLE IV-3B. COOLING TOWER VOC EMISSIONS INCREASE

Emissions Unit	Recirculation Rate, gpm	Emission Factor, lb/10^6 gallon	VOC, lb/hr	VOC, TPY	Past Actual, TPY	Net, TPY
BLD-307CT, Cell 12	4,200	0.7	0.18	0.8	0.0	**0.8**
Alky CT [1]	18,000	0.7	0.76	3.3	3.3	**0.0**

1. Alky cooling tower will be repaired with no increase in capacity.

Equipment Fugitives

The proposed projects will result in an increase in VOC emissions from equipment leaks due to the installation of equipment such as flanges, valves, compressors, drains, and pumps. Fugitive emitting equipment is associated with each of the proposed projects. The emissions increases for equipment leaks are calculated using design-basis fugitive counts along with 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." Sewer component (QQQ) emission factors are from AP-42, Fourth Edition, 9/85, and "VOC Emissions from Petroleum Refinery Wastewater Systems – Background Information for Proposed Standards", EPA-450/3-85-001a, 2/85.

Tables IV-4 through IV-11 present the emissions increase from fugitive emissions from new construction for the USLD project and for new added components in other process units associated with the project. A summary of fugitive emission increases is given in Table IV-12.

Table IV-4. ULSD Fugitive Equipment Parameters and Emissions

Type of Component	Number of Components	Emission Factors, lb/hr-source	VOC, lb/hr	VOC, TPY
GGG Components Added:				
Gas valves	220	0.00253	0.557	2.44
Light liquid valves	40	0.00468	0.187	0.82
Heavy liquid valves	1280	0.00051	0.561	2.46
Flanges	6160	0.00013	0.801	3.51
Light liquid pumps	4	0.04509	0.180	0.79
Heavy liquid pumps	44	0.04718	2.08	9.09
Gas compressors	4	0.50265	2.01	8.81
Gas relief valves to atmosphere	0	0.22928	0	0
Gas relief valves to flare [1]	20	0.00459	0.092	0.40
Sample Stations	16	0.03307	0.529	2.32
QQQ Components Added:				
Process drains (controlled)	50	0.03500	1.750	7.67
Junction (or water draw) boxes (controlled)	15	0.07000	1.050	4.60
Overall Emissions Increase			**9.89**	**43.3**
GGG Components Removed:	0		0	0
QQQ Components Removed:	0		0	0
Overall Emissions Decrease			0	0
GGG Net Emissions Change			7.09	31.0
QQQ Net Emissions Change			2.80	12.3
Overall Net Emissions Change			**9.89**	**43.3**

[1] The flare control efficiency is assumed to be 98%.

Table IV-5. South Plant and East Plant FGRU Fugitive Equipment Parameters and Emissions

Type of Component	Number of Components	Emission Factors, lb/hr-source	VOC, lb/hr	VOC, TPY
GGG Components Added:				
Gas valves	602	0.00253	1.52	6.67
Light liquid valves	0	0.00468	0	0
Heavy liquid valves	0	0.00051	0	0
Flanges	218	0.00013	0.028	0.12
Light liquid pumps	0	0.04509	0	0
Heavy liquid pumps	0	0.04718	0	0
Gas compressors	6	0.50265	3.02	13.2
Gas relief valves to atmosphere	0	0.22928	0	0
Gas relief valves to flare [1]	4	0.00459	0.018	0.08
Sample Stations	2	0.03307	0.066	0.29
QQQ Components Added:				
Process drains (controlled)	22	0.03500	0.770	3.37
Junction (or water draw) boxes (controlled)	0	0.07000	0	0
Overall Emissions Increase			**5.42**	**23.8**
GGG Components Removed:	0		0	0
QQQ Components Removed:	0		0	0
Overall Emissions Decrease			**0**	**0**
GGG Net Emissions Change			4.65	20.4
QQQ Net Emissions Change			0.77	3.37
Overall Net Emissions Change			**5.42**	**23.8**

1. The flare control efficiency is assumed to be 98%.

Table IV-6. No. 5 FCCU Upgrade Fugitive Equipment Parameters and Emissions

Type of Component	Number of Components	Emission Factors, lb/hr-source	VOC, lb/hr	VOC, TPY
GGG Components Added:				
Gas valves	12	0.00253	0.030	0.13
Light liquid valves	24	0.00468	0.112	0.49
Heavy liquid valves	12	0.00051	0.006	0.03
Flanges	168	0.00013	0.022	0.10
Light liquid pumps	4	0.04509	0.180	0.79
Heavy liquid pumps	4	0.04718	0.189	0.83
Gas compressors	0	0.50265	0	0
Gas relief valves to atmosphere	0	0.22928	0	0
Gas relief valves to flare [1]	0	0.00459	0	0
Sample Stations	3	0.03307	0.099	0.43
QQQ Components Added:				
Process drains (controlled)	0	0.03500	0	0
Junction (or water draw) boxes (controlled)	0	0.07000	0	0
Overall Emissions Increase			**0.639**	**2.80**
GGG Components Removed:	0		0	0
QQQ Components Removed:	0		0	0
Overall Emissions Decrease			**0**	**0**
GGG Net Emissions Change			0.639	2.80
QQQ Net Emissions Change			0	0
Overall Net Emissions Change			**0.639**	**2.80**

1. The flare control efficiency is assumed to be 98%.

Table IV-7. No. 2 CTU Upgrade Fugitives Equipment Parameters and Emissions

Type of Component	Number of Components	Emission Factors, lb/hr-source	VOC, lb/hr	VOC, TPY
GGG Components Added:				
Gas valves	0	0.00253	0	0
Light liquid valves	20	0.00468	0.094	0.41
Heavy liquid valves	20	0.00051	0.010	0.04
Flanges	100	0.00013	0.013	0.06
Light liquid pumps	0	0.04509	0	0
Heavy liquid pumps	4	0.04718	0.189	0.83
Gas compressors	0	0.50265	0	0
Gas relief valves to atmosphere	0	0.22928	0	0
Gas relief valves to flare [1]	0	0.00459	0	0
Sample Stations	0	0.03307	0	0
QQQ Components Added:				
Process drains (controlled)	0	0.03500	0	0
Junction (or water draw) boxes (controlled)	0	0.07000	0	0
Overall Emissions Increase			**0.306**	**1.34**
GGG Components Removed:	0		0	0
QQQ Components Removed:	0		0	0
Overall Emissions Decrease			**0**	**0**
GGG Net Emissions Change			0.306	1.34
QQQ Net Emissions Change			0	0
Overall Net Emissions Change			**0.306**	**1.34**

1. The flare control efficiency is assumed to be 98%.

Table IV-8. Alky Upgrade Fugitive Equipment Parameters and Emissions

Type of Component	Number of Components	Emission Factors, lb/hr-source	VOC, lb/hr	VOC, TPY
GGG Components Added:				
Gas valves	12	0.00253	0.03	0.13
Light liquid valves	18	0.00468	0.084	0.37
Heavy liquid valves	0	0.00051	0	0
Flanges	105	0.00013	0.014	0.06
Light liquid pumps	2	0.04509	0.090	0.39
Heavy liquid pumps	0	0.04718	0	0
Gas compressors	0	0.50265	0	0
Gas relief valves to atmosphere	0	0.22928	0	0
Gas relief valves to flare [1]	0	0.00459	0	0
Sample Stations	2	0.03307	0.066	0.29
QQQ Components Added:				
Process drains (controlled)	0	0.03500	0	0
Junction (or water draw) boxes (controlled)	0	0.07000	0	0
Overall Emissions Increase			**0.285**	**1.25**
GGG Components Removed:	0		0	0
QQQ Components Removed:	0		0	0
Overall Emissions Decrease			**0**	**0**
GGG Net Emissions Change			0.285	1.25
QQQ Net Emissions Change			0	0
Overall Net Emissions Change			**0.285**	**1.25**

1. The flare control efficiency is assumed to be 98%.

Table IV-9. No. 3 CRU Reformer Main Furnace
Fugitive Emissions Parameters and Emissions

Type of Component	Number of Components	Emission Factors, lb/hr-source	VOC, lb/hr	VOC, TPY
GGG Components Added:				
Gas valves	25	0.00253	0.063	0.28
Light liquid valves	25	0.00468	0.117	0.51
Heavy liquid valves	0	0.00051	0	0
Flanges	180	0.00013	0.023	0.10
Light liquid pumps	0	0.04509	0	0
Heavy liquid pumps	0	0.04718	0	0
Gas compressors	0	0.50265	0	0
Gas relief valves to atmosphere	0	0.22928	0	0
Gas relief valves to flare [1]	0	0.00459	0	0
Sample Stations	0	0.03307	0	0
QQQ Components Added:				
Process drains (controlled)	0	0.03500	0	0
Junction (or water draw) boxes (controlled)	0	0.07000	0	0
Overall Emissions Increase			**0.204**	**0.89**
GGG Components Removed:	0		0	0
QQQ Components Removed:	0		0	0
Overall Emissions Decrease			**0**	**0**
GGG Net Emissions Change			0.204	0.89
QQQ Net Emissions Change			0	0
Overall Net Emissions Change			**0.204**	**0.89**

1. The flare control efficiency is assumed to be 98%.

Table IV-10. Saturated Gas Plant Upgrade and Fire Rebuild Fugitive Equipment Parameters and Emissions

Type of Component	Number of Components	Emission Factors, lb/hr-source	VOC, lb/hr	VOC, TPY
GGG Components Added:				
Gas valves	78	0.00253	0.197	0.86
Light liquid valves	397	0.00468	1.858	8.14
Heavy liquid valves	154	0.00051	0.079	0.34
Flanges	458	0.00013	0.060	0.26
QQQ Components Added:				
Process drains (controlled)	0	0.03500	0	0
Overall Emissions Increase			**2.194**	**9.60**
GGG Components Removed:				
Gas valves	82	0.00253	0.207	0.91
Light liquid valves	362	0.00468	1.694	7.42
Heavy liquid valves	156	0.00051	0.080	0.35
Flanges	385	0.00013	0.050	0.22
Heavy Liquid Pumps	1	0.04718	0.047	0.21
QQQ Components Removed:				
Process Drains (Controlled) [2]	1	0.03500	0.035	0.15
Overall Emissions Decrease			**0**	**0**
GGG Net Emissions Change			0.116	0.49
QQQ Net Emissions Change			-0.035	-0.15
Overall Net Emissions Change			**0.081**	**0.34**

1. The flare control efficiency is assumed to be 98%.
2. Sewer component factors are from AP-42 Fourth Edition, September 1985 and "VOC Emissions from Petroleum Refinery Wastewater Systems – Background Information for Proposed Standards". EPA-450/3-85-001a, Feb. 1985

Table IV-11. No. 4 FCCU Upgrade Fugitive Equipment Parameters and Emissions

Type of Component	Number of Components	Emission Factors, lb/hr-source	VOC, lb/hr	VOC, TPY
GGG Components Added:				
Gas valves	6	0.00253	0.015	0.07
Light liquid valves	12	0.00468	0.056	0.25
Heavy liquid valves	0	0.00051	0	0
Flanges	36	0.00013	0.005	0.02
Light liquid pumps	0	0.04509	0	0
Heavy liquid pumps	0	0.04718	0	0
Gas compressors	0	0.50265	0	0
Gas relief valves to atmosphere	0	0.22928	0	0
Gas relief valves to flare [1]	0	0.00459	0	0
Sample Stations	0	0.03307	0	0
QQQ Components Added:				
Process drains (controlled)	0	0.03500	0	0
Junction (or water draw) boxes (controlled)	0	0.07000	0	0
Overall Emissions Increase			**0.076**	**0.33**
GGG Components Removed:	0		0	0
QQQ Components Removed:	0		0	0
Overall Emissions Decrease			**0**	**0**
GGG Net Emissions Change			0.076	0.33
QQQ Net Emissions Change			0	0
Overall Net Emissions Change			**0.076**	**0.33**

1. The flare control efficiency is assumed to be 98%.

TABLE IV-12. FUGITIVE EMISSIONS INCREASES SUMMARY

Emission Unit	Net Emissions, TPY
USLD Project	43.3
South Plant and East Plant FGRU	23.8
No. 5 FCCU Upgrade	2.80
No. 2 CTU Upgrade	1.34
Alky Upgrade	1.25
No. 3 CRU Main Furnace	0.89
Saturated Gas Plant Upgrade and Fire Rebuild	0.34
No. 4 FCCU Upgrade	0.33

Total Fugitive VOC Emissions	**74.1**

Storage Tanks

A new 100,000-barrel hydrocarbon liquid storage tank (T-1101) will be installed in support of the ULSD project. The tank will be equipped with an internal floating roof (IFR) and have an annual throughput of approximately 4 MMbbl/yr. The ULSD project will result in an additional 2,500 BPD of naphtha being sent to storage from the No. 9 HDT stripper overhead. Tank T-119 will receive this increased naphtha throughput. Emissions for T-1101 and T-119 were calculated based on the anticipated throughput for each tank using U.S. EPA's TANKS 4.09 program. VOC emissions increases are shown in Table IV-13.

TABLE IV-13. STORAGE TANKS VOC EMISSIONS INCREASE

Emissions Unit	Type	Throughput, MMbbl/yr	New VOC Emissions, TPY
New Tank T-1101	IFR	4.0	**11.5**
Existing Tank T-119	EFR	0.9 [1]	**33.2**

1. Increased throughput of 2,500 BPD

FCCUs

The No. 4 FCCU project will improve unit product yield distribution. Also, new emission controls required by the Consent Decree, including the use of low-NO_X combustion promoter and NO_X and SO_X emission reduction additives, will decrease NO_X and SO_2 emissions from the unit. Emissions decreases resulting from the additives are not creditable for PSD netting. However, these decreases are accounted for in the air quality modeling.

The No. 5 FCCU project will increase the throughput of the unit, which will result in higher CO emissions from the regenerator. As with the No. 4 FCCU, the No. 5 FCCU is required by the Consent Decree to use low-NO_X combustion promoter and NO_X emission reduction additive to decrease NO_X emissions from the unit. In addition, a Selective Non-Catalytic Reduction (SNCR) unit will be installed in CO boiler B-5004 to further reduce NO_X emissions. Finally, a wet gas scrubber (WGS) will be installed on the No. 5 FCCU to reduce PM_{10} and SO_2 emissions.

Use of the NO_X emission reduction additive and installation of the SNCR are specific requirements of the Consent Decree while the WGS is necessary for the No. 5 FCCU to meet the PM_{10} emissions limits of NESHAP 40 CFR Part 63, Subpart UUU (MACT II), as well as Consent Decree-specified SO_2 emission limits. Emissions decreases resulting from the additives, the SNCR, and the WGS are not creditable for PSD netting. However, these decreases are accounted for in the air quality modeling.

The operating parameters and emission factors for the No. 5 FCCU are shown in Table IV-14. Table IV-15 gives the emissions increases from the No. 5 FCCU and Table IV-16 gives the emissions increases from the No. 4 FCCU.

Table IV-14. No. 5 FCCU Parameters and Emission Factors

Future Max Rate, BPD	Future Max Air Rate, lb/hr	Regenerator Pressure, psia	Pollutant	Emission Factors [1]	Units
48,000	391,500	58	CO	2.87	lb/Mbbl
			PM/PM_{10}	1.13E-02	lb PM –psia/lb air
			NO_X	37.8	lb/Mbbl
			NO_X	18.9	lb/Mbbl w/$DeNO_x$ additive
			SO_2	193	lb/Mbbl
			SO_2	25	ppmv in flue gas
			VOC	- [2]	

1. Emission factors based on stack testing data. CO, NO_x, and SO_2 based on 2/10/98 stack test and PM based on 2/01/04 stack test.
2. FCC operates with excess oxygen resulting in complete combustion of VOCs.

TABLE IV-15. NO. 5 FCCU EMISSIONS INCREASES

Pollutant	PTE No controls, TPY	PTE [1] w/ additives, TPY	PTE [2, 3] w/ SNCR + $DeNO_X$ additives + WGS, TPY	Actual Emissions, TPY	Emissions Increase, TPY
CO	25.1	25.1	25.1	11.7	**13.4**
PM/PM_{10}	334	334	120	279	**-159**
NO_x	331	165	116	146	**-30**
SO_2	1690	514	257	734	**-477**
VOC	0	0	0	0	**0**

1. Based on $DeSO_X$ and $DeNO_X$ additive, 50% reduction in NO_X, 50 ppmv SO_2 concentration in stack.
2. Based on 30% reduction of NO_X due to SNCR
3. Based on 64% reduction of PM_{10} and 25 ppmv SO_2 concentration in stack.

Table IV-16. No. 4 FCCU Emissions Increases

Pollutant	PTE w/additives, TPY	Actual Emissions, TPY	Emissions Increase, TPY
CO	110 [1]	68.2	**41.8**
PM/PM_{10}	145 [2]	144	**0.6**

NO_x	87 [3]	163	**-76**
SO_2	333 [3]	492	**-159**
VOC	8.3 [4]	5.1	**3.2**

1. Based on current permit limitation of 150 ppm CO @ 0% O_2.
2. Based on March 28, 2002 and May 20-21, 2003 stack tests and safety factor.
3. Based on current operations with NO_X and SO_2 reduction additives and safety factor.
4. Based on current permit limitation.

Wastewater System

The existing wastewater treatment system will be used to process the increased wastewater flow resulting from the proposed projects. ConocoPhillips estimates a maximum flow rate increase through the wastewater treatment system of approximately 11%. The associated emissions increase was calculated by multiplying the 2002 calendar year wastewater emissions by 11%. The emissions increase from the wastewater treatment system is shown in Table IV-17.

TABLE IV-17. WASTEWATER SYSTEM VOC EMISSIONS INCREASE

2002 Emissions, TPY	Percent Increase	VOC Increase, TPY
19.2	11	**2.0**

Hydrogen Plant

The ULSD project includes installation of a new hydrogen plant, which will include a deaerator vent as part of the hydrogen purification process. Emissions from this vent are estimated to include water vapor, carbon dioxide, carbon monoxide, methanol, and ammonia. Due to the low heating value of this type of stream, hydrogen plant deaerator vents are exempt from control under NESHAP Subpart CC (Refinery MACT). At present, selection of the hydrogen plant vendor has not been completed. However, ConocoPhillips estimated worst-case VOC emissions from the deaerator vent to be as shown in Table IV-18.

TABLE IV-18. HYDROGEN PLANT VENT EMISSIONS INCREASE

CO, TPY	VOC, TPY	Ammonia, TPY
3.0	25.0	9.0

Emissions Increases Summary

Table IV-19 summarizes the project emissions increases from all new and modified sources. Table IV-20 summarizes the project emissions increases for all associated sources that will be used for both PSD Applicability and PSD Netting. Table IV-21 summarizes the project emissions increases for associated sources that will be used for PSD Applicability only. The

emissions increases from these associated sources were already considered in the application for Permit 2002-476-C (PSD). Emissions increases are based on maximum future potentials less actual emissions.

Table IV-19. Project Emissions Increases from New and Modified Sources

New/Modified Sources	NO_X, TPY	SO_2, TPY	CO, TPY	VOC, TPY	PM_{10}, TPY
ULSD Project					
H-1001 #4 HDT Heater	6.6	5.4	5.3	0.7	1.0
H-9901 #9 HDT Heater	8.8	7.2	7.0	1.0	1.3
H-9902 Stripper Reboiler	11.0	9.0	8.8	1.2	1.6
ULSD-5/5a Reformer Furnace	92.8	50.8	49.5	6.7	9.3
T-1101 Tank	0	0	0	11.5	0
H_2 Plant Deaerator Vent	-	-	3.0	25.0	-
No. 3 CRU Project					
NH-6007 Reformer Main Furnace	38.3	31.4	30.7	4.1	5.7
Main Power Project					
NB-0001/NB-0002 Steam Boilers	161	132	129	17.3	24.1
No. 2 CTU					
H-6014 Preflash Tower Reboiler [3]	-	12.4	-	0.7	0.9
H-6015 Vacuum Tower Heater [3]	-	22.7	-	1.6	2.2
No. 5 FCCU Project					
H-5001 Feed Preheater [1]	-	18.2	1.9	1.4	2.0
Cooling Tower Expansion	0	0	0	0.8	0.2
No. 5 FCCU (Regenerator) [5]	-	-	13.4	0.0	-
Alky Project					
H-0057 Depropanizer Reboiler [2]	0.0	11.1	-	0.6	0.8
H-0058 Depropanizer Reboiler [2]	0.0	7.7	-	0.4	0.5
H-0059 Depropanizer Reboiler [3]	-	11.1	-	0.6	0.8
No. 4 FCCU Project					
No. 4 FCCU (Regenerator) [4]	-	-	41.8	3.2	0.6
All Projects					
Equipment Fugitives	0	0	0	74.1	0
TOTAL	**319**	**319**	**290**	**151**	**51.0**

1. NO_X reductions are the result of Consent Decree compliance and are not creditable.
2. CO reductions are the result of Consent Decree compliance and are not creditable.
3. NO_X and CO reductions are the result of Consent Decree compliance and are not creditable.
4. NO_X and SO_2 reductions are the result of Consent Decree compliance and are not creditable.
5. NO_X, SO_2, and PM_{10} reductions are the result of Consent Decree compliance and are not creditable.

Table IV-20. Project Emissions Increases from Associated Sources (PSD Applicability, PSD Netting, and Modeling Analyses)

Associated Sources	NO_X, TPY	SO_2, TPY	CO, TPY	VOC, TPY	PM_{10}, TPY
H-6151 No. 4 FCCU Preheater	17.8	14.0	15.0	1.0	1.3
H-003 No. 4 CTU Charge Heater [1]	2.8	3.2	-	0.2	0.2
H-004 No. 4 CTU Charge Heater [2]	-	14.3	-	0.7	1.0
H-6005 No. 2 CTU Tower Atmospheric Heater	39.5	25.0	3.1	0.8	1.3
Tanks Existing Naphtha Storage Tank	0.0	0.0	0.0	33.2	0.0
Wastewater Activated Sludge Unit	0.0	0.0	0.0	2.0	0.0
Total	**60.1**	**56.5**	**18.1**	**37.9**	**3.8**

1. CO reductions are the result of Consent Decree compliance and are not creditable.
2. NO_X and CO reductions are the result of Consent Decree compliance and are not creditable.

Table IV-21. Project Emissions Increases from Associated Sources (PSD Applicability Only)

Associated Sources	NO_X, TPY	SO_2, TPY	CO, TPY	VOC, TPY	PM_{10}, TPY
H-0001 No. 1 CTU Crude Charge Heater [1]	-	20.6	-	0.6	0.9
H-0005 No. 1 CTU Crude Charge Heater	16.4	13.1	13.7	0.9	1.4
H-0016 No. 1 CTU Vacuum Charge Heater	16.4	18.0	18.7	2.5	3.5
H-0023 No. 5 HDT Charge Heater	22.6	6.8	11.5	0.7	1.0
H-0028 No. 7 Coker Process Heater	31.6	22.9	11.7	0.7	1.8
H-0029 No. 7 Coker Process Heater	13.8	9.5	9.8	0.7	0.8
H-0046 No. 2 CRU Charge Heater	10.7	8.8	9.3	0.5	1.2

Associated Sources	NO_X, TPY	SO_2, TPY	CO, TPY	VOC, TPY	PM_{10}, TPY
H-0048 No. 2 CRU Reactor Preheater [1]	-	42.1	-	1.2	1.7
H-6012 No. 3 CRU Desulfurizer Heater	4.2	4.9	3.3	0.2	0.5
H-6013 No. 3 CRU Desulfurizer Heater	8.1	12.3	1.5	1.0	1.4
H-0010 Sat Gas Plant Naphtha Stabilizer Reboiler	12.2	6.8	10.2	0.7	0.9
H-0011 No. 7 HDT Heater	0.9	2.0	0.6	0.1	0.1
H-7501 No. 6 HDT Heater [2]	11.4	5.1	-	0.2	0.7
Total	**148**	**173**	**90.3**	**10.0**	**15.9**

1. NO_X and CO reductions are the result of Consent Decree compliance and are not creditable.
2. CO reductions are the result of Consent Decree compliance and are not creditable.

PSD Applicability

Table IV-22 shows the total applicable emission increase for each PSD regulated pollutant. Each emission increase is the sum of the emissions increases for each pollutant in Tables IV-19, IV-20, and IV-21 above. The total project emission increase for each pollutant is compared to the PSD Significant Emission Rate (SER) for that pollutant to determine if a PSD netting analysis is required. As shown in Table IV-22, the emission increase for each PSD regulated pollutant is above the SER. Therefore, a PSD netting analyses, based on steps 2 through 6 of the PSD netting procedure, is required for each pollutant.

TABLE IV-22. PROJECT EMISSION INCREASE FOR PSD REGULATED POLLUTANTS

Pollutant	Emission Rate, tpy	PSD Significant Emission Rate, tpy	PSD Netting Analysis Required?
NO_X	527	40	Yes
SO_2	549	40	Yes
CO	398	100	Yes
VOC	199	40	Yes
PM_{10}	70.7	15	Yes

Note: Emission rates are the summation of Tables IV-19, IV-20, and IV-21.

The total project is a major modification for all PSD pollutants and a PSD netting analysis is required. Table IV-22 accounted for all of the associated sources to verify PSD applicability. Table IV-23 summarizes the emissions increases that will be used for the subsequent steps of the PSD netting analysis and modeling analysis. Each emission increase is the sum of the emissions increases for each pollutant in Tables IV-19 and IV-20 above. The associated emissions in Table

IV-21, from process heaters H-0001, H-0005, H-0016, H-0023, H-0028, H-0029, H-0046, H-0048, H-6012, H-6013, H-0010, H-0011, and H-7501 are not considered in the PSD netting analysis because previous Permit 2002-476-C (PSD) estimated emissions increases for these units at their corresponding maximum capacity. If these sources were considered associated emissions increases for this project, then their emissions would be double counted for PSD permitting purposes.

Table IV-23. Project Emission Increase for PSD Regulated Pollutants (PSD Netting)

Pollutant	Emission Rate, TPY
NO_X	379
SO_2	376
CO	308
VOC	189
PM_{10}	54.8

Note: Emission rates are the summation of Table IV-19 and Table IV-20.

Step 2. Contemporaneous Period

According to OAC 252:100-8-31, *"an increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs within 3 years before the date that the increase from the particular change occurs".* In agreement with recent discussions with the DEQ, ConocoPhillips has interpreted the contemporaneous period to be three years prior to the start of construction through the start of operation. Therefore, for this project, the contemporaneous period begins October 1, 2001 and ends December 31, 2006.

Step 3. Emissions Increases and Decreases During the Contemporaneous Period

Contemporaneous emissions increases and decreases are those emissions associated with new construction, a physical change, or change in the method of operation of a source that begins operation during the contemporaneous period. Contemporaneous emissions decreases are those emissions decreases associated with new construction, a physical change, change in the method of operation of a source, or reductions in actual emissions from a federally-enforceable emission limit that begin operation during the contemporaneous period.

<u>Project-Related and Consent Decree-Related Emission Decreases</u>

The No. 4 HDT feed heater, H-0047, and the existing No. 3 CRU reformer main furnace, H-6007, will be decommissioned as a part of the ULSD and No. 3 CRU projects. Emission decreases resulting from the shutdown of these heaters were determined using emission inventories from 2001 and 2002. Emissions reductions from shutting down H-6007 will be creditable since emissions increases from construction of a new heater, NH-6007, are included.

Two existing Cogeneration Unit natural gas-fired turbines (Combustion Turbines 1 & 2) with heat recovery steam generator (HRSG) duct burners (COG 1DB and COG 2DB) are presently located at the refinery and in operation. Oklahoma Gas & Electric (OG&E) owns and operates the combustion turbines and ConocoPhillips owns and operates the duct burners. All these units will be removed from service during the first half of 2006, which is within the contemporaneous period for this permit. U.S. EPA guidance indicates that credit can be taken for decommissioning a cogeneration facility owned by another entity. Therefore, ConocoPhillips has elected to take credit for the emissions decreases associated with the shut down of the combustion turbines in addition to taking credit for shutdown of the duct burners. Actual emissions for the combustion turbines were determined based on the most recent representative two years (2000 and 2002) reported emissions for each unit. Year 2001 was not selected as representative because the turbines experienced significant downtime during this period. Actual emissions for the duct burners were based on the 2001 and 2002 reported emissions for each unit. NO_X emissions credits available from shutdown of the duct burners will not be used for PSD purposes; however, in the future, ConocoPhillips may apply these credits toward NO_X reduction activities required by the Consent Decree.

The following projects are related to or required by the Consent Decree and will result in emissions decreases:

1. Installation of $ULNO_X$ burners on No. 2 CTU heaters H-6014 and H-6015 and addition of a federally enforceable limitation for CO emissions of 0.04 lb/MMBtu (365-day rolling average).
2. Installation of $ULNO_X$ burners on No. 5 FCCU heater H-5001 and addition of a federally enforceable limitation for CO emissions of 0.04 lb/MMBtu (365-day rolling average).
3. Installation of $ULNO_X$ burners on HF Alkylation unit heaters H-0057, H-0058 and H-0059 and addition of a federally enforceable limitation for CO emissions of 0.04 lb/MMBtu (365-day rolling average).
4. Shutdown of, or installation of $ULNO_X$ burners in, No. 3 CRU heater H-6007.
5. Use of emissions reduction additives (low-NO_X combustion promoter and NO_X and SO_X reducing additives) in the No. 4 FCCU.
6. Use of emissions reduction additives (low-NO_X combustion promoter and NO_X reducing additive) in the No. 5 FCCU.
7. Installation of a Selective Non-Catalytic Reduction (SNCR) unit in No. 5 FCCU CO boiler B-5004.
8. Installation of a wet gas scrubber (WGS) on the No. 5 FCCU regenerator/CO boiler stack.
9. Implementation of equipment and/or instrumentation that support good air pollution control practices as approved by EPA on the South Plant and East Plant flare stacks.

Emissions decreases resulting from these projects are not creditable for PSD netting. However, these decreases are accounted for in the air quality modeling.

<u>Other Contemporaneous Emission Increases and Decreases</u>

ConocoPhillips determined other contemporaneous emission increases and decreases through a review of the current refinery permit history and future planned refinery projects. A summary of the contemporaneous emissions increases and decreases is provided in Table IV-24. As mentioned previously, not all emissions changes included in Table IV-24 are creditable.

Table IV-24. Summary of Contemporaneous Emissions Changes

Permit Date	Permit, Item, or Project	Description	Emission Increases or Decreases, TPY				
			CO	PM_{10}	NO_X	SO_2	VOC
8/23/01	98-169-C (M-2)	No. 5 FCCU [5]	76.0	14.6	24.9	16.9	38.8
10/01/01	2001-173-C	No. 7 Coker Flare Gas Recovery Project [1]	-183	-	-25.3	-1170	-32.8
11/01/01	N/A	Naphtha Caustic Treating [2]	1.0	2.6	11.7	20.6	-
12/01/01	N/A	Naphtha Booster Pumps [2]	4.1	0.4	10.5	1.0	-
01/03/02	2001-305-C	No. 3 Catalytic Reformer	14.7	5.4	-36.6	39.1	-
03/01/02	N/A	Butamer Turnaround (TA) [2]	3.2	0.9	13.3	0.5	-
04/01/02	N/A	No. 6 HDT Re-tray [2]	0.5	0.04	0.6	0.03	-
10/07/02	2001-311-C	Heater H-0001	-16.1	-	-135	-	-
6/02/03	2002-115-C	No. 4 CTU/CVU Expansion	72.5	14.1	39.3	7.1	8.7
7/14/03	97-286-C (M-3)	No. 2 CTU Naphtha Debottlenecking	15.7	9.0	32.4	34.2	1.2
1/20/04	2001-194-C (M-2)	Low Sulfur Gasoline	308	28.4	155	133	237
4/01/04	2002-476-C (PSD)	No. 1 CTU Bottoms Upgrade	241	39.9	313	272	36.9
04/01/04	2002-476-C (PSD)	H-0015 Shutdown	-12.8	-1.2	-15.2	-1.6	-0.8
10/01/04	Item 1	H-6014 & H-6015 $ULNO_X$ burners & CO limitation [4]	-4.0	-	-31.9	-	-
10/01/04	Item 5	No. 4 FCCU NO_X and SO_X Emissions Reduction Additives [4]	-	-	-75.7	-387	-
10/01/04	Items 6, 7, 8	No. 5 FCCU NO_X Emissions Reduction Additive, SNCR and WGS [4]	-	-159	-29.5	-477	-
10/01/04	ULSD	H-0047 Shutdown [4]	-4.6	-0.4	-5.5	-0.1	-0.3
10/01/05	Item 4	H-6007 Shutdown [4]	-27.2	-2.5	-77.5	-0.6	-1.8
10/01/05	Item 2	H-5001 $ULNO_X$ burners [4]	-	-	-20.0	-	-
10/01/05	Item 3	H-0057, H-0058 & H-0059 $ULNO_X$ burners [4]	-12.4	-	-0.1	-	-

05/01/06	USLD	Combustion Turbine 1 Shutdown [3]	-2.4	-6.5	-177.0	-4.8	-23.2
05/01/06	USLD	Combustion Turbine 2 Shutdown [3]	-1.8	-5.3	-190.0	-3.6	-22.4
05/01/06	USLD	HRSG Duct Burner 1 Shutdown [3]	-27.1	-13.6	-90.6	-2.6	-33.9
05/01/06	USLD	HRSG Duct Burner 2 Shutdown [3]	-23.2	-11.6	-72.6	-2.0	-29.0

1. 200 tpy of SO_2 emission decreases from this project were required by consent order C.O. 00-196.
2. ConocoPhillips estimated emissions and project timing.
3. The Cogeneration Unit combustion turbines and HRSG duct burners will be shut down during the 1st half of 2006.
4. These units will be modified or removed from service as part of the projects included in this permit.
5. The permit memorandum for 98-169-C (M-2) incorrectly calculates the project increases for NO_X and CO. The emission increases were corrected in the contemporaneous and creditable table in Permit No. 2002-194-C (PSD).

Step 4. Creditable Emissions Changes

A contemporaneous increase or decrease is creditable only if the DEQ has not relied upon it in previously issuing a PSD permit. In addition, the PSD permit must be in effect when the emissions increase or decrease from the proposed modification occurs. For pollutants with PSD increments, a contemporaneous increase or decrease in actual emissions which occurs before the baseline date in an area is creditable only if the increase or decrease would be considered in calculating how much of an increment remains available for the pollutant in question. A contemporaneous decrease is creditable only to the extent that it is federally enforceable from the moment that construction begins on the project with the contemporaneous emissions decrease. A source cannot take credit for a contemporaneous decrease that it has had to make, or will have to make, in order to bring an emissions unit into compliance. Furthermore, a source cannot take credit for an emission reduction of potential emissions from an emissions unit that was permitted, but never built or operated.

Several contemporaneous projects were relied upon in previous PSD permits, including the Low Sulfur Gasoline Project, Permit No. 2001-194-C (PSD), and the No. 1 CTU Upgrade Project, Permit No. 2002-476-C (PSD). Emissions increases and decreases from previously relied upon contemporaneous projects are not creditable towards the proposed projects. Table IV-25 provides a summary of the contemporaneous and creditable emission changes relied upon in the PSD netting for the proposed projects in this permit.

Table IV-25. Evaluation of Contemporaneous and Creditable Projects

Permit Date	Permit, Item, or Project	Description	Creditable?
8/23/01	98-169-C (M-2)	No. 5 FCCU [2]	No
10/01/01	2001-173-C	No. 7 Coker Flare Gas Recovery Project [1]	Yes (CO, SO_2, VOC)
11/01/01	N/A	Naphtha In-Line Caustic Treating [2]	No

Permit Date	Permit, Item, or Project	Description	Creditable?
12/01/01	N/A	Naphtha Booster Pumps [2]	No
01/03/02	2001-305-C	No. 3 Catalytic Reformer [7]	No
03/01/02	N/A	Butamer Turnaround (TA) [2]	No
04/01/02	N/A	No. 6 HDT Re-tray [2]	No
10/07/02	200-311-C	Heater H-0001 [5]	No
6/2/03	2002-115-C	No. 4 CTU/CVU Expansion [2]	No
07/14/03	97-286-C (M-3)	No. 2 CTU Naphtha Debottlenecking [1]	Yes (CO, SO_2, VOC)
1/20/04	2001-194-C (M-2)	Low Sulfur Gasoline [2]	No
04/01/04	2002-476-C (PSD)	No. 1 CTU Bottoms Upgrade [1]	Yes (CO, SO_2, VOC)
04/01/04	2002-476-C (PSD)	H-0015 Shutdown [8]	Yes (CO, SO_2, VOC)
10/01/04	Item 1	H-6014 & H-6015 $ULNO_X$ burners [4]	No
10/01/04	Item 5	No. 4 FCCU NO_X and SO_X Emissions Reduction Additives [4]	No
10/01/04	Items 6,7,8	No. 5 FCCU NO_X Emissions Reduction Additive, SNCR, and WGS [4]	No
10/01/04	USLD	H-0047 Shutdown	Yes
10/01/05	Item 4	H-6007 Shutdown [9]	Yes (CO, PM_{10}, SO_2, VOC)
10/01/05	Item 2	H-5001 $ULNO_X$ burners [4]	No
10/01/05	Item 3	H-0057, H-0058 & H-0059 $ULNO_X$ burners [4]	No
05/01/06	USLD	Combustion Turbine 1 Shutdown [3]	Yes
05/01/06	USLD	Combustion Turbine 2 Shutdown [3]	Yes
05/01/06	USLD	HRSG Duct Burner 1 Shutdown [3, 6]	Yes (CO, PM_{10}, SO_2, VOC)
05/01/06	USLD	HRSG Duct Burner 2 Shutdown [3, 6]	Yes (CO, PM_{10}, SO_2, VOC)

1. Only emissions of CO, SO_2 and VOC are considered creditable since emissions of PM_{10} and NO_X were previously relied upon for Permit No. 2002-476-C PSD.
2. These projects were previously relied upon in Permit No. 2001-194-C PSD and are, therefore, not creditable for this permit.
3. The Cogeneration Unit combustion turbines and HRSG duct burners will be shut down during the 1st half of 2006.
4. Emission reductions resulting from these projects are not creditable because they are necessary for compliance with the Consent Decree.

5. This project is not creditable because it was required by consent order C.O. 00-196.
6. NO_X emission credits available from shutdown or modification of this equipment will be applied toward NO_X reduction activities required by the Consent Decree.
7. Emissions of CO, SO_2, VOC, and PM_{10} were previously relied upon in Permit No. 2001-194-C PSD and are, therefore, not creditable for this permit. NO_X reductions are creditable since they were not relied upon in Permit No. 2001-194-C; however, NO_X reductions will not be used for this permit. 36.6 TPY NO_X credits will be applied toward NO_X reduction activities required by the Consent Decree.
8. Only emissions of CO, SO_2, VOC, and NO_X are considered creditable since emissions of PM_{10} were previously relied upon for Permit No. 2002-476-C PSD; however, NO_X reductions will not be used for this permit. 15.2 TPY NO_X credits will be applied toward NO_X reduction activities required by the Consent Decree.
9. Emission reductions of CO, SO_2, VOC, and PM_{10} are creditable since emissions from construction of replacement heater, NH-6007, were included as new emissions.

Step 5. Amount of Emissions Increase and Decrease

A summary of the contemporaneous and creditable emission increases and decreases for each PSD pollutant is presented in Table IV-26.

Table IV-26. Summary of Contemporaneous Emission Increases and Decreases

Permit Date	Permit Number, Item, or Project	Description	Emission Increases or Decreases, TPY				
			CO	PM_{10}	NO_X	SO_2	VOC
10/01/01	2001-172-C	No. 7 Coker Flare Gas Recovery Project	-183	-	-	-1170	-32.8
07/14/03	97-286-C (M-3)	No. 2 CTU Naphtha Debottlenecking	15.7	-	-	34.2	1.2
04/01/04	2002-476-C (PSD)	No. 1 CTU Upgrade	241	-	-	272	36.9
04/01/04	2002-476-C (PSD)	H-0015 Shutdown [2]	-12.8	-	-	-1.6	-0.8
10/01/04	ULSD	H-0047 Shutdown [1]	-4.6	-0.4	-5.5	-0.1	-0.3
10/01/05	Item 4	H-6007 Shutdown [1, 2]	-27.2	-2.5	-	-0.6	-1.8
05/01/06	ULSD	Combustion Turbine 1 Shutdown [1]	-2.4	-6.5	-177	-4.8	-23.2
05/01/06	ULSD	Combustion Turbine 2 Shutdown [1]	-1.8	-5.3	-190	-3.6	-22.4
05/01/06	ULSD	HRSG Duct Burner 1 Shutdown[1, 2]	-27.1	-13.6	-	-2.6	-33.9
05/01/06	ULSD	HRSG Duct Burner 1 Shutdown[1, 2]	-23.2	-11.6	-	-2.0	-29.0
Total			**-25.4**	**-39.9**	**-373**	**-879**	**-106**

1. These sources are being removed from service as part of the proposed projects included in this permit application.
2. NO_X emission credits available from shutdown or modification of this equipment will be applied toward NO_X reduction activities required by the Consent Decree.

Step 6. PSD Review Applicability

Table IV-27 summarizes the net emissions increase for each PSD pollutant for this project.

TABLE IV-27. NET EMISSIONS INCREASES FROM THE PROJECT

Pollutant	Emission Increase, TPY [1]	Creditable Contemporaneous Emissions, TPY [2]	Net Emission Increase, TPY	PSD Significant Emission Rate, TPY	Subject to PSD Review?
CO	308	-25.4	**283**	100	Yes
PM_{10}	54.8	-39.9	**14.9**	15	No
NO_X	379	-373	**6**	40	No
SO_2	376	-879	**-503**	40	No
VOC	189	-106	**83**	40	Yes

1. From Table IV-23
2. From Table IV-26

The project is subject to PSD review for each regulated pollutant for which the sum of all creditable emissions increases and decreases results in a significant net emission increase. Additional prospective and creditable emission reductions sufficient to provide for a less than significant net emission increase at the source may be proposed to avoid PSD review. As shown in Table IV-27, a PSD review is not required for PM_{10}, NO_X, and SO_2. Emissions of CO and VOC require a full PSD review. The PSD review for CO and VOC is presented in Section V.

SECTION V. PSD Review for Pollutants CO and VOC

A full PSD review consists of the following steps:

1. Determination of best available control technology (BACT).
2. Analysis of air quality impacts. This analysis includes:
   - Description of dispersion model and procedures
   - Determination of air quality impact significance
   - Determination of pre-construction monitoring requirements
   - Compliance with National Ambient Air Quality Standards (NAAQS)
   - Compliance with available PSD increments
3. Evaluation of source-related impacts on growth, soils, vegetation, and visibility.
4. Evaluation of Class I Area impacts.

In addition, the proposed project is subject to certain Federal and State standards including, but

not limited to, NSPS 40 CFR Part 60, Subparts A, Db, J, Kb, GGG, and QQQ, and NESHAP 40 CFR Part 63, Subpart CC (MACT I), Subpart UUU (MACT II), and Subpart DDDDD.

1. Determination of BACT

OAC 252:100-8-1.1 defines BACT as *"...the control technology to be applied for a major source or modification is the best that is available as determined by the Director on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs of alternate control systems."*

A BACT analysis is required to assess the appropriate level of control for each new or physically modified emissions unit for each pollutant that exceeds the applicable PSD SER. As shown in Section IV, only net emissions of CO and VOC exceed the PSD SER.

The U.S. EPA has stated its preference for a "top-down" approach for determining BACT and that is the methodology used for this permit review. After determining whether any New Source Performance Standard (NSPS) is applicable, the first step in this approach is to determine, for the emission unit in question, the available control technologies, including the most stringent control technology, for a similar or identical source or source category. If any of the control technologies are technically infeasible for the emission unit in question, that control technology is eliminated from consideration. The remaining control technologies are then ranked by effectiveness and evaluated based on energy, environmental, and economic impacts beginning with the most stringent remaining technology. If it can be shown that this level of control should not be selected based on energy, environmental, or economic impacts, then the next most stringent level of control is evaluated. This process continues until the BACT level under consideration cannot be eliminated by any energy, environmental, or economic concerns. The five basic steps of a top-down BACT review are summarized as follows:

Step 1. Identify Available Control Technologies
Step 2. Eliminate Technically Infeasible Options
Step 3. Rank Remaining Control Technologies by Control Effectiveness
Step 4. Evaluation of Remaining Control Technologies Based on Energy, Environmental, and Economic impacts
Step 5. Select BACT and Document the Selection as BACT

The U.S. EPA has consistently interpreted statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available control technologies, i.e., those that provide the maximum degree of emissions reduction. Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of energy, environmental, and economic impacts.

The new or modified CO and/or VOC emission sources for this project are:

A. Process heaters H-1001, H-9901, H-9902, USLD-5/5a, NH-6007, H-6014, H-6015, H-5001, H-0057, H-0058, and H-0059, and steam boilers B-0009 and B-0010
B. Fluid catalytic cracking units (No. 4 FCCU and No. 5 FCCU)
C. Equipment Leaks
D. Tank T-1101
E. No. 5 FCCU Cooling Tower
F. H_2 Plant Deaerator Vent

Potentially applicable emission control technologies were identified by researching the U.S. EPA control technology database, technical literature, and control equipment vendor information and by using process knowledge and engineering experience. The RACT/BACT/LAER Clearinghouse (RBLC), a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies that have been approved in PSD permits as BACT for numerous types of process units. Process units in the database are grouped into categories by industry.

A. BACT Analysis for Process Heaters & Boilers

CO Emissions

Step 1. Identify Available Control Technologies

The available control technologies identified for CO emission control for process heaters and boilers are presented in Table V-1.

Table V-1. Available Control Technologies for Process Heaters and Boilers

Pollutant	Control Technologies
CO	Thermal Oxidation
	Catalytic Oxidation
	$ULNO_X$ Burners
	Good Combustion Practice

<u>Thermal Oxidation</u>

Thermal oxidizers combine temperature, time, and turbulence to achieve complete combustion. Thermal oxidizers are equivalent to adding another combustion chamber where more oxygen is supplied to complete the oxidation of CO. The waste gas is passed through burners, where the gas is heated above its ignition temperature. Additional fuel is required to reach this higher temperature, which adds to the operating cost of the unit. The hot gases then pass through one or more residence chambers to ensure complete combustion.

Thermal oxidizers require operating temperatures in the 1,300°F to 2,000°F range to ensure conversion of CO to CO_2. The higher temperatures provide the highest conversion rate. The combustion process occurs in two separate stages: (1) the combustion of fuels and (2) the combustion of pollutants. The combustion process in the first stage is an extremely rapid and irreversible chemical reaction. The oxygen supplied by the primary air may be in excess or obtained directly from the process gas stream. In the second stage of the process, the heated gases from the burners pass through residence chambers, where the CO is oxidized. Efficiency is dependent on residence time, heating value of the gas stream, and operating temperatures.

Catalytic Oxidation

Catalytic oxidation allows complete oxidation to take place at a faster rate and at a lower temperature than is possible with thermal oxidation. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 feet per second (fps) to 30 fps. Catalytic oxidizers typically operate at 650°F to 1,000°F.

Catalytic oxidizers cannot be used on waste gas streams containing significant amounts of particulate matter as the particulate deposits foul the catalyst and prohibit oxidation. High temperatures can also accelerate catalyst deactivation; however, that is normally not a concern with flue gas from process heaters and boilers.

$ULNO_X$ Burners

$ULNO_X$ burners were developed to provide increasing lower levels of NO_X emissions. However, when operated using good combustion practices, they can also provide significant reductions in CO emissions.

There are several designs of $ULNO_X$ burners available. $ULNO_X$ burners combine two NO_X reduction steps into one burner, which is typically staged air with internal flue gas recirculation (IFGR) or staged fuel with IFGR.

In staged air burners with IFGR, fuel is mixed with part of the combustion air to create a fuel rich zone. High-pressure atomization of the fuel creates the recirculation. Secondary air is routed by means of pipes or ports in the burner block to optimize the flame and complete combustion. This design is predominately used with liquid fuels.

In staged fuel burners with IFGR, fuel pressure induces the IFGR, which creates a fuel lean zone and a reduction in oxygen partial pressure. This design is predominately used for gas fuel applications.

Good Combustion Practice

Good combustion practice includes operational and design elements to control the amount and distribution of excess air in the flue gas. This ensures that there is enough oxygen present for complete combustion. If sufficient combustion air, temperature, residence time, and mixing are

incorporated in the combustion design and operation, CO emissions are minimized. The design of modern, efficient combustion equipment is such that there is adequate turbulence in the flue gas to ensure good mixing, a high temperature zone (greater than 1,800°F) to complete burnout, and sufficient residence time at the high temperature (one to two seconds).

Good combustion practice is the industry standard for CO control of process heaters and boilers. Operators control CO emissions by maintaining various operational combustion parameters. Modern combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions.

Step 2. Eliminate Technically Infeasible Options

A search of the RBLC database indicated that thermal and catalytic oxidation have rarely been applied to process heaters or boilers. Typically, higher concentrations of CO in the pollutant stream are needed to justify the use of thermal oxidation and catalytic oxidation. However, neither control option can be eliminated as technically infeasible. Therefore, all of the technologies mentioned above will be examined for energy, environmental, and economic impacts.

Step 3. Ranking of Remaining Control Technologies by Control Effectiveness

Table V-2 presents the control technologies and their approximate control efficiencies.

Table V-2. Approximate Control Efficiencies for CO

Control Technology	Range of CO Reduction, %	Typical CO Reduction, %	Typical Emission Level, lb/MMBtu
Thermal Oxidation	75-95	90	0.0082
Catalytic Oxidation	75-95	90	0.0082
$ULNO_X$ Burners	25-75	50	0.040
Good Combustion Practice	Base Case	Base Case	0.082

Step 4. Evaluation of Remaining Control Technologies

<u>Thermal Oxidation</u>

Thermal oxidation requires raising the flue gas temperature to 1,300°F to 2,000°F in order to complete the CO oxidation. Depending on specific furnace and thermal oxidizer operation parameters (fuel gas heating value, excess oxygen in the flue gas, flue gas temperature, and oxidizer temperature) raising the flue gas temperature can require an additional heat input of 10 to 25% above the process heater heat input, which is a negative for energy considerations.

Depending on the design of the thermal oxidizer, emissions of NO_X, SO_2, and PM_{10} could also be 10 to 25% higher than emissions without a thermal oxidizer. However, since NO_X and SO_2

pollutants will be controlled for all new and modified heaters in this project, the emission increase for these pollutants with a thermal oxidizer would not be considered unreasonable. Neither would increases in PM_{10} emissions since emissions of PM_{10} are relatively low from gas-fired heaters.

Installation costs and operating costs (mostly from the 10 to 25% increase in fuel consumption) are significant. Permit 2001-194-C (PSD), which was issued in July 2002, estimated the annual cost for controlling CO emissions by thermal oxidation from four new process heaters and one new boiler at the Ponca City Refinery (PCR). The heaters and boilers had similar heat rates (33 MMBtu/hr to 480 MMBtu/hr) and CO emission rates (0.0824 lb/MMBtu) as the sources in this BACT analysis. The annual costs ranged from $20,000 to $45,000 per ton of CO controlled. Installation costs to retrofit existing heaters would be significantly higher and perhaps infeasible due to structure and space limitations.

A search of the RBLC and recently issued permits in attainment areas indicated that thermal oxidation has not been selected as BACT. Therefore, based on the additional use of energy, the increase in emissions of other pollutants, the associated costs, and no previous documentation of thermal oxidation as BACT; thermal oxidation is eliminated from consideration as BACT for this project.

Catalytic Oxidation

Catalytic oxidation allows complete oxidation to take place at a faster rate and at a lower temperature than is possible with thermal oxidation. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 feet per second (fps) to 30 fps. Catalytic oxidizers typically operate at 650°F to 1,000°F. This can require from 0 to 10% in additional fuel and a resulting similar increase in other pollutant emissions. Neither of these results would be considered unreasonable for natural gas combustion. An additional environmental consideration is the disposal of spent catalyst, which is considered a hazardous material.

Permit 2001-194-C (PSD), which was issued in July 2002, estimated the annual cost for controlling CO emissions from four new process heaters and one new boiler at the PCR by catalytic oxidation. The annual costs ranged from $12,000 to $34,000 per ton of CO controlled. Installations costs to retrofit existing heaters would be significantly higher and perhaps infeasible due to structure and space limitations. This is especially true for those heaters that need additional heat to raise stack temperatures to required temperatures for catalytic oxidation.

A search of the RBLC and recently issued permits in attainment areas indicated that catalytic oxidation was rarely selected as BACT. Therefore, based on the additional use of energy, the possible increase in emissions of other pollutants, the associated costs, and no previous documentation of catalytic oxidation as BACT; catalytic oxidation is eliminated from consideration as BACT for this project.

$ULNO_X$ Burners

A review of the RBLC database indicated that $ULNO_X$ burners were selected as BACT for a number of PSD permits. These determinations were usually made on the basis that the $ULNO_X$ burners were BACT for NO_X and would also be selected as BACT for CO. As the $ULNO_X$ burners technology has achieved lower emissions of NO_X, the burners have also provided lower emissions of CO. Recent BACT determinations have shown CO emissions ranging from 0.02 to 0.06 lb/MMBtu, with 0.04 lb/MMBtu as the most typical lowest emission.

Good Combustion Practice

Good combustion practice is the industry standard for CO control of process heaters and boilers. Operators control CO emissions by maintaining various operational combustion parameters. Modern combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions. There is no increased energy requirement or increased pollutants with good combustion practice. The RBLC database lists this option as the most prevalent form of BACT for controlling CO emissions from process heaters and boilers. Modern heater and burner designs combined with good combustion practice by the operator can produce CO emissions as low as 0.082 lb/MMBtu for standard burners and as low as 0.02 lb/MMBtu for $ULNO_X$ burners.

Step 5. Select BACT and Document the Selection as BACT

All the new and modified process heaters and boilers for this project will be equipped with $ULNO_X$ burners, which are required by the Consent Decree. ConocoPhillips is required by the Consent Decree to achieve a maximum CO emission rate of 0.04 lb/MMBtu (365-day rolling average). Therefore, a maximum CO emission rate of 0.04 lb/MMBtu (365-day rolling average) is the selected BACT for the process heaters and boilers and will be accomplished by good combustion practice.

VOC Emissions

Step 1. Identify Available Control Technologies

The available control technologies identified for VOC emission control for process heaters and boilers are presented in Table V-3. These are the same control technologies discussed for CO control and the same technology descriptions apply for control of VOC and are not repeated.

Table V-3. Available VOC Control Technologies for Process Heaters and Boilers

Pollutant	Control Technologies
VOC	Thermal Oxidation
	Catalytic Oxidation
	$ULNO_X$ Burners
	Good Combustion Practice

Step 2. Eliminate Technically Infeasible Options

A search of the RBLC database indicates that thermal and catalytic oxidation have rarely been applied to process heaters or boilers. Typically, higher concentrations of VOC in the pollutant stream are needed to justify the use of thermal oxidation and catalytic oxidation. However, neither control option can be eliminated as technically infeasible. Therefore, all of the technologies mentioned above will be examined for energy, environmental, and economic impacts.

Step 3. Ranking of Remaining Control Technologies by Control Effectiveness

Table V-4 presents the control technologies and their approximate control efficiencies. Note that VOC emissions are typically less than 10% of CO emissions for gas-fired heaters and boilers.

Table V-4. Approximate Control Efficiencies for VOC

Control Technology	Range of VOC Reduction, %	Typical VOC Reduction, %	Typical Emission Level, lb/MMBtu
Thermal Oxidation	75-95	90	0.00054
Catalytic Oxidation	75-95	90	0.00054
$ULNO_X$ Burners	0-75	45	0.0030
Good Combustion Practice	Base Case	Base Case	0.0054

Step 4. Evaluation of Remaining Control Technologies

<u>Thermal Oxidation</u>

The technology evaluation for VOC control is the same as for CO control, except that base VOC emissions are much lower. The costs to control both CO and VOC would be about $18,000 to $41,000 per ton. Installation costs to retrofit existing heaters would be significantly higher and perhaps infeasible due to structure and space limitations.

A search of the RBLC and recently issued permits in attainment areas indicated that thermal oxidation has not been selected as BACT. Therefore, based on the additional use of energy, the increase in emissions of other pollutants, the associated costs, and no previous documentation of thermal oxidation as BACT; thermal oxidation is eliminated from consideration as BACT for this project.

<u>Catalytic Oxidation</u>

The technology evaluation for VOC control is the same as for CO control, except that base VOC

emissions are much lower. The costs to control both CO and VOC would be about $11,000 to $31,000 per ton. Installation costs to retrofit existing heaters would be significantly higher and perhaps infeasible due to structure and space limitations. This is especially true for those heaters that need additional heat to raise stack temperatures to required temperatures for catalytic oxidation.

A search of the RBLC and recently issued permits in attainment areas indicated that catalytic oxidation was rarely selected as BACT. Therefore, based on the additional use of energy, the possible increase in emissions of other pollutants, the associated costs, and no previous documentation of catalytic oxidation as BACT, catalytic oxidation is eliminated from consideration as BACT for this project.

<u>$ULNO_X$ Burners</u>

All the new and modified process heaters and boilers for this project will be equipped with $ULNO_X$ burners, which are required by the Consent Decree. A review of the RBLC database indicated that $ULNO_X$ burners were selected as LAER for a few PSD permits, but not as BACT. Use of $ULNO_X$ burners can provide VOC emission rates as low as 0.0030 lb/MMBtu (LAER), but typical emissions are 0.0054 lb/MMBtu.

<u>Good Combustion Practice</u>

Good combustion practice is the industry standard for VOC control of process heaters and boilers. Operators control VOC emissions by maintaining various operational combustion parameters. Modern combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions. There is no increased energy requirement or increased pollutants with good combustion practice. The RBLC database lists this option as the most prevalent form of BACT for controlling VOC emissions from process heaters and boilers.

Step 5. Select BACT and Document the Selection as BACT

Thermal oxidation and catalytic oxidation were eliminated from consideration based on energy, environmental, and economic considerations. Use of $ULNO_X$ burners has been selected as LAER, but not BACT. Therefore, a maximum VOC emission rate of 0.0054 lb/MMBtu is the selected BACT for the process heaters and boilers and will be accomplished by good combustion practice.

B. BACT Analysis for FCCUs

CO Emissions

Step 1. Identify Available Control Technologies

Control devices considered in the BACT analysis must meet applicable NSPS to be considered viable. For FCCU regenerators, NSPS Subpart J requires that CO concentrations in the flue gas be less than 500 ppmvd on a continuous basis. The Consent Decree also requires that the FCCU

regenerators at the refinery meet a concentration limit of 150 ppmvd at 0% O_2 on a 365-day rolling average. Therefore, any control technology that cannot meet Subpart J requirements and the Consent Decree requirements will not be considered BACT. Available control technologies for CO emissions from the No. 4 and No. 5 FCCU regenerators at the Ponca City Refinery are listed in Table V-5.

Table V-5. Available CO Control Technologies for FCCU

Pollutant	Control Technology
CO	Thermal Oxidation (CO Boiler)
	Catalytic Oxidation
	CO Combustion Promoter

Thermal Oxidation (CO Boiler)

Thermal oxidation is based on the concepts of temperature, time, and turbulence to achieve complete combustion. Use of a CO boiler is equivalent to adding a combustion chamber where the regenerator vent gas is heated above its ignition temperature. Excess O_2 is supplied to complete the conversion of CO to CO_2. Additional fuel is required to reach this higher temperature. CO boilers operate at approximately 1,800°F to ensure conversion of CO to CO_2. The combustion process is thought of as occurring in two separate stages: (1) the combustion of fuels, and (2) the combustion of pollutants.

Refiners who operate partial combustion FCCUs use CO boilers to control CO emissions. Partial combustion FCCUs operate at temperatures below 1,250°F. The lower operating temperatures result in combustion characteristics that lead to regenerator vent gas CO concentrations well in excess of 500 ppmdv. Once the vent gas passes through the CO boiler, the CO concentrations are comparable to those of a high-temperature regeneration FCCU. Refiners operating high-temperature regeneration FCCUs do not require the use of a CO boiler because CO concentrations in high-temperature regenerator effluents are typically already less than 500 ppmdv.

Catalytic Oxidation

Catalytic oxidizers are an alternative to thermal oxidizers. A solid catalyst is used to create a heterogeneous reaction. A catalyst is an element or compound that speeds up a reaction without undergoing change itself. The catalyst allows complete oxidation to take place at a faster rate and at a lower temperature than is capable in thermal oxidation.

In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst at a velocity in the 10 to 30 fps range. Catalytic oxidizers typically operate at 650°F to 1,000°F. Approximately 1.5 to 2.0 ft^3 of catalyst is required per 1,000 SCFM of gas (waste gas plus supplementary fuel combustion products).

The main problem in catalytic oxidizers is the loss of catalyst activity. They cannot be used on waste gas streams containing significant amounts of particulate matter. Particulate deposits foul the catalyst and prohibit oxidation. High temperatures also accelerate catalyst deactivation. Short-term temperatures above 1,500°F can cause significant loss of catalyst activity.

CO Combustion Promoter

Complete oxidation of CO to CO_2 takes place in an ideally designed and operated regenerator. However, since ideal conditions cannot always be reached and maintained during industrial operation, many petroleum refiners use a CO combustion promoter. The promoter is a platinum and/or palladium catalyst that is injected into full combustion regenerators only as needed to ensure that CO concentrations remain below 500 ppmdv.

While use of a CO combustion promoter can lower the CO content of the flue gas, it also has some drawbacks. Promoter is frequently added to the regenerator two to three times a day at a rate of 3 to 5 pounds per ton of fresh FCCU catalyst. It increases the requirement for combustion air and raises the regenerator temperature; thus, increasing thermal deactivation of the catalyst. It is also important to verify that the metallurgy in the regenerator is designed to accommodate a higher temperature operation.

An additional drawback related to CO combustion promoter use is formation of NO_X. The Consent Decree requires the use of low-NO_X combustion promoter (non-platinum) in addition to NO_X reducing additive at the No. 4 and No. 5 FCCUs.

Step 2. Eliminate Technically Infeasible Options

Catalytic Oxidation

FCCU regenerator flue gas contains entrained particulate matter. Catalytic oxidation cannot be used on waste gas streams containing particulate due to the potential for catalyst fouling, which prohibits oxidation. Catalytic oxidation is considered technically infeasible based on the significant amount of particulate matter contained in the flue gas from an FCCU regenerator. The RBLC has no record of catalytic oxidation being used as CO control for this emission source.

Step 3. Ranking of Remaining Control Technologies by Control Effectiveness

Table V-6 provides a list of the remaining CO control technologies ranked by effectiveness.

Table V-6. Remaining CO Control Technologies

Control Technology	Effectiveness
Thermal Oxidation (CO Boiler)	50 - 500 ppmdv
CO Combustion Promoter	50 - 500 ppmdv

Step 4. Evaluation of Remaining Control Technologies

Thermal Oxidation (CO Boiler)

Refiners who operate partial combustion FCCUs use CO boilers to control CO emissions. Refiners operating FCCUs in a full combustion mode, also known as high-temperature regeneration, do not require the use of a CO boiler. High-temperature regeneration and partial combustion regeneration followed by a CO boiler achieve comparable results and can achieve CO concentrations between 50 and 150 ppmdv. No further analysis is required as the No. 4 FCCU is designed and operated as a high-temperature regeneration unit and the No. 5 FCCU currently utilizes a CO boiler.

CO Combustion Promoter

CO concentrations in the range of 50 to 150 ppmvd in the flue gas have been achieved by the use of CO combustion promoter at the No. 4 FCCU and the No. 5 FCCU units at the PCR. No further analysis of this technology is required.

Step 5. Select BACT and Document the Selection as BACT

Based on the different existing design parameters of the No. 4 and No. 5 FCCUs, two different BACT were selected. The No. 4 FCCU operates at a high regenerator temperature. Occasional CO combustion promoter usage achieves emission CO concentrations less than 150 ppmdv. Therefore, the Consent Decree limitation of 150 ppmvd at 0% O_2 (365-day rolling average) is considered BACT and will be achieved with the use of CO combustion promoter in the No. 4 FCCU. The No. 5 FCCU operates at a lower regenerator temperature, which results in higher CO emissions. The No. 5 FCCU currently utilizes a CO boiler that, along with the occasional use of CO combustion promoter, controls CO emissions below 150 ppmvd. Therefore, the Consent Decree limitation of 150 ppmvd at 0% O_2 (365-day rolling average) is selected as BACT and will be achieved with the current CO boiler control device and the use of CO combustion promoter for the No. 5 FCCU.

VOC Emissions

Step 1. Identify Potential Control Technologies

Table V-7 lists the available technologies for control of VOC emissions from FCCU.

Table V-7. Available VOC Control Technologies for FCCU

Pollutant	Control Technology
VOC	Thermal Oxidation
	Catalytic Oxidation
	Good Combustion Practice

Thermal oxidation and catalytic oxidation control technologies are the same as the technologies described above for CO control and the same parameters apply; therefore, the description of those technologies is not repeated. Both FCCUs already operate with a form of thermal oxidation as described previously.

Good Combustion Practice

Operators of FCCU regenerators control regenerator air flow and regeneration temperature to insure proper coke burn in order to keep the catalyst as active as possible. This is considered good combustion practice.

Step 2. Eliminate Technically Infeasible Options

FCCU regenerator flue gas contains entrained particulate matter. Catalytic oxidation cannot be used on waste gas streams containing particulate due to the potential for catalyst fouling, which prohibits oxidation. Catalytic oxidation is considered technically infeasible based on the significant amount of particulate matter contained in the flue gas from an FCCU regenerator. The RBLC has no record of catalytic oxidation being used as VOC control for this emission source.

Step 3. Ranking of Remaining Control Technologies by Control Effectiveness

The FCCUs at the PCR presently use thermal oxidation to control CO emissions. The No. 4 FCCU regenerator operates at a high temperature between 1,300°F and 1,400°F, which is typical of a thermal oxidizer. The No. 5 FCCU is equipped with a CO boiler that is, essentially, a form of thermal oxidation. No further ranking is required as good combustion practice is the remaining additional control option.

Step 4. Evaluation of the Most Effective Controls

The FCCUs are already equipped with a form of thermal oxidation. The formation of VOC can be controlled using good combustion practice. Proper operation of the FCCU regenerators is required to ensure proper coke burn. Therefore, proper operation of the FCCU regenerators (i.e., good combustion practice) ensures control of VOC emissions.

Step 5. Select BACT and Document the Selection as BACT

Catalytic oxidation control is considered infeasible. The FCCUs operate with a form of thermal oxidation to control VOC emissions. Therefore, BACT is good combustion practice, which is accomplished by proper operation of the FCCU regenerators.

C. BACT Analysis for Equipment Leaks

There are no CO emissions in fugitive emissions from equipment leaks; therefore, only VOC emissions are considered.

Step 1. Identify Potential Control Technologies

Leak detection and repair (LDAR) programs are the control technology for control of equipment leaks. The effectiveness of LDAR programs can vary depending on the specific requirements of the federal or state standard. The LDAR programs identified for the control of equipment fugitives at refineries are presented in Table V-8.

Table V-8. VOC Control Technologies for Equipment Leaks

Control Technology	Regulations
Petroleum Refinery NESHAP	40 CFR Part 63, Subpart CC
Petroleum Refinery NSPS	40 CFR 60, Subpart GGG

Step 2. Eliminate Technically Infeasible Options

Each LDAR program listed as a potential control technology is technically feasible; therefore, no programs are eliminated due to technical infeasibility.

Step 3. Ranking of Remaining Control Technologies by Control Effectiveness

Table V-9 summarizes the control efficiencies of the potential LDAR programs.

Table V-9. Remaining VOC Control Technologies for Equipment Leaks

Control Technology	Approximate Control Efficiency, % [1]
Petroleum Refinery NESHAP	91-95
Petroleum Refinery NSPS	81-88

1. Approximate control efficiencies were obtained from the U.S. EPA Refinery Tier 2 BACT Analysis Report, Final Report dated January16, 2001.

Step 4. Evaluation of the Most Effective Controls

<u>Petroleum Refinery NESHAP</u>

The requirements of the petroleum refinery NESHAP (hereafter referred to as the Refinery MACT) include monthly monitoring of pumps and valves to detect leaks, and provisions for monitoring the seal system or barrier fluid system of compressors. The Refinery MACT also provides a definition of the VOC concentration level that constitutes equipment leaks. Leak

detection readings consistently below the leak threshold can result in a decrease in the monitoring frequency.

Information from an EPA publication (*Petroleum Refinery Tier 2 BACT Analysis Report*, Morrisville, North Carolina, January, 2001) gives the total annualized cost of complying with the Refinery MACT monitoring requirements as about $27,000 for a hydrotreater at a large refinery, which is defined as having a crude capacity above 50,000 bbl/day. Assuming a 93% reduction in VOC emissions as a result of implementing the Refinery MACT LDAR requirements, the cost per ton of VOC controlled at the ULSD unit is approximately $630. This cost is economically feasible for BACT. For this analysis, it is assumed that the implementation of the Refinery MACT LDAR requirements to other process equipment will also be economically feasible.

Petroleum Refinery NSPS

The petroleum refinery NSPS requires monthly monitoring of pumps and valves. The definitions of what constitute equipment leaks are not reduced based on the amount of time the equipment has been in service. Leak detection readings for valves consistently below the leak threshold can result in a decrease in the monitoring frequency. The monitoring of pumps is required monthly regardless of previous demonstrations of having no leaks.

Because the Refinery MACT requirements are more stringent and are economically feasible, no further review of the petroleum refinery NSPS is required.

Step 5. Select BACT and Document the Selection as BACT

Each equipment fugitive entry in the RBLC database lists LDAR as BACT for equipment leak fugitives. The Refinery MACT standard is more stringent than the NESHAP standard and is considered BACT.

D. BACT Analysis for Tank T-1101

There are no emissions of CO from tank T-1101, so only VOC emissions are considered.

Step 1– Step 5. Select BACT and Document the Selection as BACT

Any new or modified storage tanks will be subject to the Refinery MACT (40 CFR Part 63 Subpart CC), which requires an internal floating roof tank with two vapor mounted seals or a mechanical shoe. The RBLC database lists floating roof as the most prevalent form of BACT. Meeting the standards of the Refinery MACT exceeds the floating roof requirement and is considered BACT.

E. BACT Analysis for No. 5 FCCU Cooling Tower

Typically, there are only very insignificant emissions of CO from refinery cooling towers. Significant VOC emissions occur due to tube leaks that can occur in heat exchangers that use cooling water to cool both vapor and liquid hydrocarbon streams.

Step 1. Identify Potential Control Technologies

Refinery operators will typically monitor for hydrocarbon tube leaks in cooling water exchangers to some extent in order to help prevent excessive growth of algae in the cooling tower water basin and water distribution devices. Hydrocarbon monitoring is periodic sampling of a stream of cooling tower water to determine VOC concentration and indications of possible tube leaks. The only identified control option for VOC emissions from cooling towers is to perform hydrocarbon monitoring; however, the frequency of monitoring and follow-up procedures can vary. The RBLC database lists hydrocarbon monitoring or a Monitoring, Inspection, and Maintenance Plan (MIMP) as the most prevalent form of BACT. Therefore, the identified potential control technologies are (1) hydrocarbon monitoring, and (2) a MIMP.

Step 2. Eliminate Technically Infeasible Options

Neither of the control technologies can be eliminated as being infeasible.

Step 3. Ranking of Remaining Control Technologies by Control Effectiveness

A MIMP is more effective than simple hydrocarbon monitoring in identifying and controlling VOC emissions from cooling towers.

Step 4. Evaluation of the Most Effective Controls

Hydrocarbon monitoring is periodic sampling of a stream of cooling tower water using a stripping unit to determine VOC concentration. These measurements allow conformity to the allowable emissions limits as well as provide an indication of possible process leaks. A MIMP is a more structured technology whereby individual equipment that is leaking VOC into the cooling water is identified and scheduled for maintenance at the earliest opportunity.

Step 5. Select BACT and Document the Selection as BACT

The applicant has proposed a MIMP with monthly hydrocarbon monitoring as BACT. All equipment will be maintained in order to minimize fugitive emissions. Any faulty equipment will be repaired at the earliest opportunity, but no later than the next scheduled unit shutdown. All results of monitoring and maintenance activities will be maintained for a period of two years and made available upon request.

F. BACT Analysis for Hydrogen Plant Deaerator Vent

Step 1-Step 5. Select BACT and Document the Selection as BACT

A search of the RBLC database indicates no records of any control technology being applied to hydrogen plant deaerator vents as BACT. On June 8, 1998 the U.S.EPA published an update to NESHAP Subpart CC in the Federal Register. The update explained that hydrogen plant deaerator vents consist mainly of carbon dioxide and water vapor with methanol concentrations of less than one percent. This vent mixture is not combustible and, due to the large vent volume, technologies to control the methanol emissions would be costly. The EPA estimated control of methanol at about $5,000 to $50,000 per ton of methanol destroyed. The EPA deemed "no controls" as MACT for hydrogen plant deaerator vents.

This leaves proper equipment operation as BACT for the hydrogen plant deaerator vent. Proper equipment operation ensures that the correct operating conditions are maintained to avoid excess formation of methanol. These conditions include reactor operating temperature, pressure and component process rates. Also, engineering judgment will be applied when selecting the hydrogen plant shift reactor catalyst type. Catalysts manufacturers are currently formulating catalysts that reduce methanol by-product formation. These catalysts will be analyzed for environmental, economical, operational properties and implemented, if possible. Current equipment design proposals utilize the lowest methanol producing catalyst currently on the market.

2. Analysis of Air Quality Impacts

An air impact analysis is required for a major modification of an existing PSD major source that results in a significant net emission increase for any pollutant. As previously shown, this project resulted in a significant net emission increase for CO and VOC.

A description of the dispersion model and procedures used for the model is provided in the ambient air impact analysis. The analysis also includes a determination of air impact significance based on Modeling Significance Level (MSL), determination of any pre-application monitoring requirements based on Monitoring De Minimis Concentrations, compliance with the NAAQS (if required), and compliance with available PSD increments (if required).

VOCs act as precursors to tropospheric ozone formation. The EPA regulates ozone partially by regulating VOC emissions. VOC and ozone are unique in that the EPA has not established a PSD Modeling Significance Level or PSD increments for either VOC or ozone. The EPA has established a Monitoring De Minimis Concentration for ozone, which is different from other criteria pollutants because it is based on a mass emission rate of VOC (100 tpy) instead of a modeled ambient concentration of VOC (in units of $\mu g/m^3$ or ppm_v). Since the EPA has not established a MSL for VOC and since the project net VOC emissions increases do not exceed the 100 tpy de minimis level, the impact on ozone is considered as not significant and a full ambient air impact analysis for compliance with the NAAQS is not required.

An air impact analysis for CO emissions follows.

Description of dispersion model and procedures

The dispersion model analysis for this project was conducted using the latest version (99020) of the Industrial Source Complex Short-Term Version 3 (ISCST3) model with Plume Rise Model Enhancements (ISC-PRIME) to estimate ground-level concentrations. The prime algorithms have been coupled with the regulatory ISCST3 model to form the ISC-PRIME model.

Land Use Dispersion Coefficients

Based on a review of the USGS Ponca City, Oklahoma, Quadrangle 7.5 minute series topographic map and the Land Use and Land Cover map for the region immediately surrounding the refinery, the Auer typing scheme of the land use patterns was used for this analysis. It was determined that the adjacent land use is more than 50 percent urban. Therefore, urban dispersion coefficients are used in this modeling analysis.

Terrain

The ISC-PRIME model optionally calculates concentrations based on flat or elevated terrain. For this modeling analysis, elevated terrain was used. The receptor terrain elevations entered into the model were the highest elevations extracted from USGS 1:24,000 scale (7.5 minute series) digital elevation model (DEM) data of the area surrounding the refinery. DEM is a digital file consisting of terrain elevations for ground positions at regularly spaced intervals. For each receptor, the maximum terrain elevation associated with the four DEM points surrounding the receptor was selected for the receptor elevations. DEM data was also used for the base elevations of refinery sources and buildings.

Building Wake Effects (Downwash)

The primary improvements associated with the PRIME dispersion model are in the algorithms that predict pollutant concentrations for plumes that are affected by building downwash. Numerous comparative studies suggest that ISC-PRIME offers a considerably more accurate representation of building downwash effects. Specifically, it is an improvement upon the downwash algorithms of the ISCST3 model in which a stack was assumed to be centrally located adjacent to the lee side of the dominant downwash structure even though the stack may actually be located upwind, or downwind, and up to five building heights away, and/or laterally displaced from the structure. ISC-PRIME improves upon these assumptions by having the ability to model streamlines in the downwind wake cavity and by employing an enhanced numerical simulation of the plume mass, buoyant energy, and momentum. As a result the plume is modeled throughout the cavity, near-wake, and far-wake regions, and the source-structure relationship is more accurately represented.

For the PSD modeling analysis, the direction-specific building dimensions used as input to the ISC-PRIME model were calculated using the BREEZE-AIR software. This software incorporates the algorithms of the U.S. EPA-sanctioned Building Profile Input Program (BPIP) (version 95086), which has been adapted to incorporate the PRIME downwash algorithms and released by the U.S. EPA as “BPIPPRM”. BPIPPRM is designed to incorporate the concepts and procedures expressed in the Good Engineering Practice (GEP) Technical Support document, the Building Downwash Guidance document, and other related documents, while incorporating the

enhancements to improve prediction of ambient impacts in building cavities and wake regions. Comparison studies have shown that ISC-PRIME induces no biases to over-predict or under-predict ambient concentrations outside of the wake and cavity regions.

Meteorological Data

The ISC-PRIME air dispersion modeling was performed using 1986 through 1988 preprocessed meteorological data based on surface observations taken from Wichita, Kansas, [National Weather Service (NWS) station number 3928] with upper air measurements from Oklahoma City, Oklahoma, (NWS station number 13967). The 1990 and 1991 preprocessed meteorological data are based on surface observations taken from Wichita, Kansas and upper air measurements from Norman, Oklahoma (NWS station number 3948). The anemometer height at the Wichita, Kansas, NWS station during the period of interest was 10.06 meters.

Receptor Grids

Ground-level concentrations were calculated for receptors within four Cartesian receptor grids. These four grids covered a region extending 20 km from all edges of the refinery fence-line. The grids are defined as follows:

1. A Fence-line Grid containing 100 meter-spaced receptors along the refinery fence-line and in areas within the refinery fence-line that are open to the public or operated by non-ConocoPhillips employees.

2. A Fine Grid containing 100 meter-spaced receptors, extending approximately 1.0 km from the fence-line, exclusive of the receptors within the Fence-line Grid.

3. A Medium Grid containing 500 meter-spaced receptors, extending approximately 4 km beyond the Fine grid.

4. A Coarse Grid containing 1,000 meter-spaced receptors, extending approximately 15 km beyond the Medium grid.

Stack Parameters

Stack parameters were obtained from several different sources. For permitted sources, the stack parameters contained in the permit memorandum were used. Stack parameters for new and un-permitted sources were obtained from current design estimates. Stack parameters used for all air quality modeling are shown in Table V-10. More detailed information, including stack locations, are available in the permit application and in the air dispersion modeling CD provided by the applicant. Stack SO_2 emissions are included in this table as a matter of convenience for an air modeling analysis that is required for state SO_2 emission standards. That analysis is addressed in Section VI.

Table V-10. Stack Parameters

Point Source	SO_2 rate	Height	Dia.	Temp.	Velocity
	g/s	meter	meter	°K	m/s
H-0001 (No. 1 CTU Crude Charge Heater)	0.85	30.5	2.07	590	8.0
H-0016 (No. 1CVU Charge Heater)	0.47	30.5	1.83	450	17.4
H-0005 (No. 1 CTU Crude Charge Heater)	0.44	36.6	1.83	675	6.2
H-0028 & H-0029 (No. 7 Coker Process Heaters)	0.98	50.6	2.29	670	22.9
H-0023 (No. 5 HDT Charge Heater)	0.20	30.5	0.91	630	20.8
H-0047 (No. 4 HDT Charge Heater)	0.0	18.3	0.85	685	8.8
H-7501 (No. 6 HDT Reactor Charge Heater)	0.15	22.4	0.91	670	12.6
H-0046 (No. 2 CRU Charge Heater)	0.26	18.3	1.01	820	14.6
H-0048 (No. 2 CRU Desulfurizer Preheater)	1.25	29.0	1.46	690	64.6
H-6007 (No. 3 CRU Reactor Preheater)	0.85	36.6	1.62	830	28.5
H-6012 (No. 3 CRU Desulfurizer Preheater)	0.14	27.5	1.28	660	4.6
H-6013 (No. 3 CRU Reactor Preheater)	0.36	27.5	1.74	730	8.0
H-0010 (Saturate Gas Plant Naphtha Reboiler)	0.22	30.5	1.43	545	5.7
H-0011 (No. 7 HDT Heater)	0.063	30.5	0.91	650	4.7
H-0057, H-0058, H-0059 (Alky Depropanizer)	0.98	53.3	2.99	500	4.4
H-5001 (No. 5 FCC Feed Preheater)	0.54	38.1	1.83	645	18.9
5FCCU (No. 5 FCC Regenerator)	7.40	53.3	2.59	525	14.1
Coker Transport Truck Loading	0	3.1	0.00	-	0.0
Coker Crusher	0	3.1	0.00	-	0.0
COGEN/Duct Burner Stack 1	0	30.5	3.34	465	7.5
COGEN/Duct Burner Stack 2	0	30.5	3.34	465	7.5
H-0003 (No. 4 CTU Charge Process Heater)	0.13	30.5	1.52	695	3.8
H-0004 (No. 4 CTU Charge Process Heater)	0.55	35.7	1.92	610	7.3
H-6005 (No. 2 CTU)	0.76	43.6	1.98	640	13.5
H-6008 (Butamer)	0	10.7	0.76	785	4.9
H-6014 (No. 2 CTU)	0.37	45.7	2.10	580	4.0
H-6015 (No. 2 CTU)	0.67	45.7	1.80	640	11.2
H-6151 (No. 4 FCCU)	0.41	40.5	1.46	660	9.8
No. 4 FCCU	3.02	53.3	1.37	495	24.8
H-5004 & H-5003 & SRU (SRU TAIL GAS)	0.15	61	0.55	935	0.2
BOILER #7 STACK	0.28	48.8	2.29	480	9.4
BOILER #4,5,6 STACK	0.20	48.8	1.83	400	16.3
BOILER #1,2,3 STACK	0	48.8	2.29	450	6.6
H-8601 (IFP Splitter Reboiler Heater)	0.76	39.6	2.36	590	6.2
H-8602 (PrimeG+ HDS Feed Heater)	0.23	39.6	1.45	645	6.1
H-8603 (Stabilizer Reboiler)	0.17	39.6	1.22	590	5.9
H-8801 (H2 Plant Reformer Heater)	0.007	39.6	1.83	450	17.4
B-0008	2.48	45.7	2.59	425	3.8
Alky Flare	0.27	45.7	0.06	1273	20.0
Truck Rack Flare	0	15.2	0.32	1273	20.0
East Plant Flare	2.62	68.6	0.09	1273	20.0
South Plant Flare	2.63	60.4	0.08	1273	20.0
West Plant Flare	2.04	61	0.10	1273	20.0

Point Source	SO_2 rate	Height	Dia.	Temp.	Velocity
	g/s	meter	meter	°K	m/s
R&D Flare	0	9.1	1.00	1273	20.0
Railcar Flare	0	15.2	1.00	1273	0.0
Flare CF	0	61	1.00	1273	20.0
H-1001 (#4 HDT Heater)	0.16	30.5	0.91	650	10.0
H-9901 (#9 HDT Heater)	0.21	30.5	1.22	650	10.0
H-9902 (#9 HDT)	0.26	30.5	1.22	650	10.0
ULSD-5/5a (H_2 Reformer Heater & H_2 Feed Heater)	1.46	30.5	1.22	650	10.0
No. 5 FCCU Cooling Tower Expansion	0	12.2	5.18	-	12.8
B-0009/B-0010	3.79	22.9	1.83	420	5.5

Determination of air quality impact significance

A Significance Analysis for carbon monoxide (CO) was completed to determine if the net emission increase would have a significant impact upon the area surrounding the refinery. If the modeled maximum ground level concentration of CO does not exceed any MSL, then the net emission increase is considered not to be significant, and a Full Impact Analysis for compliance with the NAAQS and with available PSD increments is not required. The ground level concentrations predicted in the Significance Analysis are also used to determine whether pre-construction monitoring is required and to define the radius of impact (ROI) within which a Full Impact Analysis (if required) should be conducted.

In the Significance Analysis the net CO emission increase from each applicable source is modeled. The net emission increase is based on all emission increases and decreases from any new, modified, or associated source for the proposed project and any emission increases or decreases from any source with emission changes that are both contemporaneous and creditable. ConocoPhillips was not able to count any CO emission decrease that was a result of compliance with the Consent Decree towards determination of the PSD significance level. However, those CO emission decreases can be used when determining the net emission increase for the air impact analysis. Table V-11 shows the change in CO emissions from sources due to the project and from other sources due to changes that are contemporaneous and creditable. All the sources were assumed to operate continuously, with hourly emission rates corresponding to the annual creditable emission increase or decrease.

Table V-11. Project and Contemporaneous CO Emission Increases and Decreases

Source Description	Status	ULSD & Upgrade Project	Naphtha Debottleneck Project	No. 1 CTU Upgrade Project	Contemporaneous Project Total
		TPY	TPY	TPY	TPY
H-1001	New	5.3	-	-	5.3
H-9901	New	7.0	-	-	7.0
H-9902	New	8.8	-	-	8.8
ULSD-5/5a	New	49.5	-	-	49.5
Deaerator Vent	New	3.0	-	-	3.0
H-6014	Modified	-3.3	0.6	-	-2.7

Source Description	Status	ULSD & Upgrade Project	Naphtha Debottleneck Project	No. 1 CTU Upgrade Project	Contemporaneous Project Total
		TPY	TPY	TPY	TPY
H-6015	Modified	-0.7	1.6	-	0.9
H-5001	Modified	1.9	1.3	23.4	26.6
H-0057/H-0058/ H-0059	Modified	-12.4	1.1	23.7	12.4
No. 5 FCCU	Modified	13.4	3.1	62.3	78.8
No. 4 FCCU	Modified	41.8	2.1	-	43.9
B-0009/B-0010	New	129	-	-	129
H-6151	Associated	15.0	0.5	-	15.5
H-6005	Associated	3.1	0	-	3.1
H-6007 [1]	New or Modified	30.7	-	-	30.7
H-0003	Associated	-2.3	-	-	-2.3
H-0004	Associated	-10.0	-	-	-10.0
H-0047	Associated	-4.6	0.2	4.2	-0.2
Duct Burner 1	Associated	-27.1	-	1.5	-26.6
Duct Burner 2	Associated	-23.2	-	1.5	-21.7
H-28 & H-29	Contemporaneous	-	0.9	23.3	24.2
H-23	Contemporaneous	-	0	10.3	10.3
H-7501	Contemporaneous	-	0.1	1.1	1.2
H-46	Contemporaneous	-	0.4	9.4	9.8
H-48	Contemporaneous	-	3.7	0	3.7
H-10	Contemporaneous	-	0.1	10.5	10.6
H-11	Contemporaneous	-	0	1.9	1.9
OG&E Turbine 1 & Turbine 2	Removed - ULSD	-4.2	-	-	-4.2
H-0016 (#1 CVU Charge Heater)	Contemporaneous	-	-	18.7	18.7
H-0005 (No. 1 CTU Crude Charge Heater)	Contemporaneous	-	-	12.4	12.4
H-6012 (No. 3 CRU Desulfurizer Preheater)	Contemporaneous	-	-	2.1	2.1
H-6013 (No. 3 CRU Reactor Preheater)	Contemporaneous	-	-	0.1	0.1
Alky Flare [2]	Contemporaneous	-	-	-182	-182
H-0015 (#1 CVU Charge Heater - replaced)	Contemporaneous	-	-	-12.8	-12.8

1. H-6007 was scheduled for replacement as part of No. 1 CTU Upgrade Project, but did not occur. Included in ULSD & Upgrade Project. Modeled at CO increase of 38 TPY per previous estimates.
2. CO decreases from contemporaneous project in Permit No. 2001-173-C, No. 7 Coker Flare Gas Recovery Project. The CO decreases became available once the FGR project was completed and the emission limits became federally enforceable. This occurred in 2003.

The results of the Significance Analysis for CO emissions are summarized in Table V-12.

TABLE V-12. MAXIMUM CONCENTRATIONS CALCULATED IN THE SIGNIFICANCE ANALYSIS

Pollutant	Averaging Period	Maximum Modeled Concentration	Location of Maximum		Modeling Significance Level	Monitoring De Minimis Concentration
			UTM East	UTM North		
		µg/m³	(m)	(m)	µg/m³	Mg/m³
CO	1-hour	71.7	670,982	4,061,940	2,000	575
	8-hour	94.2	670,108	4,062,520	500	-

CO concentrations are less than any MSL; therefore, a Full Impact Analysis is not required.

Determination of pre-construction monitoring requirements

The U.S. EPA's monitoring de minimis concentrations establish the levels at which a facility may need to conduct pre-construction ambient air quality monitoring to demonstrate compliance with the NAAQS and PSD Increment. If modeling analyses show that maximum concentrations from a project do not exceed the monitoring de minimis concentrations, the permitting authority has discretionary authority to exempt the facility from the pre-construction monitoring requirement. As demonstrated in Table V-12, the project does not result in ambient concentrations above the de minimis level for CO. Also, the VOC net emissions increase is not over the 100 tpy monitoring de minimis level; therefore, per OAC 252:100-8-33(c), the project is exempt from pre-construction monitoring.

Compliance with NAAQS

Net emissions of CO are below any MSL; therefore, a Full Impact Analysis is not required to demonstrate compliance with the NAAQS.

Compliance with available PSD increments

Net emissions of CO are below any MSL; therefore, a Full Impact Analysis is not required to demonstrate compliance with PSD increments.

3. Evaluation of Source-related Impacts on Growth, Soils, Vegetation, and Visibility

An additional impacts analysis considering existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the source's impact area was performed for CO and VOC as part of the PSD review.

<u>Growth Impact Analysis</u>

The elements of a growth impact analysis include a projection of the industrial, commercial, and residential growth that will occur in the area due to the proposed projects, including the potential impact upon ambient air due to this growth. No secondary or auxiliary industrial growth will occur as a result of the proposed projects, other than some possible additional acid gas processing at the Jupiter facility located next to the refinery. Since there is no significant commercial or industrial growth, negligible growth-related air pollution impacts are expected.

Soil And Vegetation Analysis

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. The gaseous pollutant acting directly on the organism can cause both acute and chronic effects. Secondary agents, such as changes in soil pH, may indirectly cause long-term effects.

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 NAAQS are intended to protect the public welfare from the adverse effects of airborne effluents. This protection extends to agricultural soil. The maximum predicted CO pollutant concentrations from the proposed projects are below the NAAQS. Therefore, no significant adverse impact on soil and vegetation due to CO emissions is anticipated from the proposed projects.

Emissions of VOC are precursors to tropospheric ozone. Elevated ground-level ozone concentrations can damage plant life and reduce crop production. VOCs interfere with the ability of plants to produce and store food, making them more susceptible to disease, insects, other pollutants, and harsh weather. No significant impact on soil and vegetation due to VOC emissions is anticipated due to the proposed projects.

Visibility Impact Analysis

The proposed projects are not expected to produce any perceptible visibility impacts in the immediate vicinity of the refinery. Given the refinery's limitation on opacity of emissions from the No. 4 and No. 5 FCCU, and a reasonable expectation that normal operation of the gas-fired heaters and boilers will result in 0% opacity, no immediate visibility impairment is anticipated.

4. Evaluation of Class I Area Impacts

The nearest Class I area to the refinery is the Wichita Mountain National Wildlife Refuge in Lawton, Oklahoma, which is located approximately 240 km to the southwest of the Ponca City Refinery. Since this area is located more than 200 km from the facility, a Class I area impact analysis is not required.

SECTION VI. State-only Air Quality Standards

The project is subject to two state-only air quality standards: OAC 252:100-31 (Control of Emissions of Sulfur Compounds) and OAC 252:100-41 (Control of Emission of Hazardous Air Pollutants and Toxic Air Contaminants). The project emissions were modeled to demonstrate compliance with these standards.

OAC 252: 100-31 (Sulfur Compounds)

Subchapter 31 specifies the maximum ground level concentrations that are allowed from sources that emit sulfur dioxide (SO_2). Emissions of SO_2 were modeled with the emission rates and the stack parameters given in Table IV-10 above. Emission sources that will experience an increase in emissions as a result of the project, as well as those being permitted but not currently constructed (No. 1 CTU Bottoms Upgrade) were modeled using potential emission rates. All other units were modeled using actual emission rates reported in the 2002 Emission Inventory. Since the Research and Development facility and Carbon Fibers facilities are permitted separately with separate SIC codes, they were not included as refinery sources for purposes of compliance with Subchapter 31. Table VI-1 presents the Subchapter 31 SO_2 standards and the modeled maximum ground level concentrations.

Table VI-1. Maximum SO_2 Concentrations

Averaging Period	Maximum Modeled Concentration	Location of Maximum		Subchapter 31 Standard
		UTM East	UTM North	
	µg/m³	(m)	(m)	µg/m³
5-minute [1]	303	-	-	1,300
1-hour	185	670,400	4,063,100	1,200
3-hour	119	670,700	4,062,700	650
24-hour	56.5	670,985	4,062,040	130

1. 5-minute values determined by multiplying 1-hour values by 1.64.

Since the maximum SO_2 concentrations are less than the state standards, the addition of the SO_2 emissions associated with the project will not cause a violation of Subchapter 31.

OAC 252: 100-41 Hazardous Air Pollutants (HAPs) and Toxic Air Contaminants (TACs)

The proposed hydrogen (H_2) plant will have an associated deaerator vent that will emit an estimated 25 tpy of methanol and 9 tpy of ammonia. Both compounds are "C" toxic air pollutants and regulated under Subchapter 41 and must meet a Maximum Ambient Air Concentration (MAAC) standard. SCREEN3 modeling was performed using the estimated emission rates and the stack parameters as presented in Table VI-2. The modeling results are

presented in Table VI-3. The reported concentration values are 24-hour averages derived from the SCREEN3 1-hour average concentration values using the 0.4 transform factor. As shown, emissions of both methanol and ammonia are in compliance with the MAAC.

Table VI-2. SCREEN3 Input Parameters

Source	Methanol Emission Rate, TPY	Ammonia Emission Rate, TPY	Stack Height, ft	Stack Diameter, in	Stack Temp, ˚F	Exit Velocity, ft/s
Hydrogen Deaerator Vent	25 [1]	9 [2]	60	4	226	100

1. 5.7 lb/hr based on continuous operation.
2. 2.1 lb/hr based on continuous operation.

Table VI-3. H_2 Deaerator Vent Modeling Results

Pollutant	Averaging Period	Maximum Modeled Concentration @ 250 m Fence Line, µg/m^3	MAAC, µg/m^3
Methanol	24-hr	45	20,216
Ammonia	24-hr	16	1,742

SECTION VII. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in "attainment" of these standards. Modeled emissions due to the project, provided in Section V, demonstrate that the facility will not have a significant impact on air quality.

OAC 252:100-4 (New Source Performance Standards) [Applicable]
Federal regulations in 40 CFR Part 60 are incorporated by reference as they exist on July 1, 2002, except for the following: Subpart A (Sections 60.4, 60.9, 60.10, and 60.16), Subpart B, Subpart C, Subpart Ca, Subpart Cb, Subpart Cc, Subpart Cd, Subpart Ce, Subpart AAA, and Appendix G. These requirements are covered in the "Federal Regulations" section.

OAC 252:100-5 (Registration, Emissions Inventory and Annual Operating Fees) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories were submitted and fees paid for previous years as required.

OAC 252:100-7 (Permits for Minor Facilities) [Not Applicable]
The refinery is a major source because the total facility emissions are greater than 100 TPY of any regulated pollutant. An application for a modification to a major (Part 70) source requires processing under Subchapter 8.

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 that result in emissions not authorized in the permit and that exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities refer to those individual emission units either listed in Appendix I 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 a HAP that the EPA may establish by rule
- 0.6 TPY of any one Category A toxic substance
- 1.2 TPY of any one Category B toxic substance
- 6.0 TPY of any one Category C toxic substance

Emission limitations and operational requirements necessary to assure compliance with all applicable requirements for all sources are taken from the construction permit application, or developed from the applicable requirement. The proposed project is considered a physical change that is considered a significant modification of a Part 70 permit; therefore, a construction permit is required. After construction, the operating permit for this modification will be incorporated into the facility's initial Part 70 permit, which is yet to be issued.
Part 7 summarizes Prevention of Significant Deterioration (PSD) requirements. See the "Federal Regulations" section for a discussion of PSD regulations.

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
In the event of any release which results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. Part 70 sources must report any exceedance that poses an imminent and substantial danger to public health, safety, or the environment as soon as is practicable. Under no circumstances shall notification be more than 24 hours after the exceedance.

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]

Section 19-4 regulates emissions of particulate matter (PM) from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating. Fuel-burning equipment is defined in OAC 252:100-1 as "combustion devices used to convert fuel or wastes to usable heat or power." Thus, the process heaters and boilers for this project are subject to the requirements of this subchapter. The most stringent fuel-burning equipment limitation is 0.10 lb/MMBtu. AP-42 (7/98) Table 1.4-2 lists PM emissions for natural gas combustion from heaters and boilers to be 0.0076 lb/MMBtu, which is in compliance. The permit will require that all the fuel-burning equipment be fired with gaseous fuel to ensure compliance with this subchapter.

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. When burning natural gas, there is very little possibility of exceeding these standards. This subchapter applies to the No. 4 FCCU and No 5. FCCU, which are both a source of emissions increases attributable to this project. The Air Quality Council granted ConocoPhillips alternate opacity limits for the No. 5 FCCU (27.5% on February 9, 1993) and the No. 4 FCCU (33% on February 18, 1998) according to the provisions of OAC 252:100-25-4. ConocoPhillips will follow the measurement and reporting provisions of the alternate opacity limit.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originated 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. Under normal operating conditions, this facility has negligible potential to violate this requirement; therefore, it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits emissions of sulfur dioxide from any one existing source or any one new petroleum and natural gas process source subject to OAC 252:100-31-26(a)(1). Ambient air concentration of sulfur dioxide at any given point shall not be greater than 1300 $\mu g/m^3$ in a 5-minute period of any hour, 1,200 $\mu g/m^3$ for a 1-hour average, 650 $\mu g/m^3$ for a 3-hour average, or 130 $\mu g/m^3$ for a 24-hour average. Part 2 also limits the ambient air impact of hydrogen sulfide emissions from any new or existing source to 0.2 ppm for a 24-hour average (equivalent to 280 $\mu g/m^3$). Compliance with the Part 2 SO_2 standards for this project was demonstrated in Section VI. This project does not involve any source with significant emissions of H_2S.
Part 5 limits sulfur dioxide emissions from new petroleum or natural gas process equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBtu heat input averaged over 3 hours. All of the new and modified process heaters and boilers for this project are subject to NSPS Subpart J, which specifies an H_2S concentration limit of 0.1 grains/dscf (160 ppm at 60°F) in the fuel gas for any new fuel combustion device. A limit of 0.1 grains/dscf of H_2S in the fuel gas is equivalent to a maximum SO_2 emission rate of 0.041 lb/MMBtu for the estimated future heating value of the refinery fuel gas.

Part 5 also limits hydrogen sulfide emissions from new petroleum or natural gas process equipment (constructed after July 1, 1972). 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. This project will produce approximately 17 LT/Day (1 LT = 2,240 lb) of incremental elemental sulfur from the new (No. 9 HDT) and modified (No. 4 HDT and No. 6 HDT) hydrotreater units. This is equivalent to approximately 1,700 lb/hr of H_2S, which is, in turn, equivalent to 3,200 lb/hr of SO_2. Approximately 90% of the incremental H_2S will be recovered in the refinery amine regenerator acid gas streams and then sent to either the refinery's Sulfur Recovery Unit (SRU) or to the Jupiter facility neighboring the refinery, both of which are designed for a minimum sulfur recovery (H_2S reduction) of 99.5% of the sulfur contained in the acid gas feed streams. The remaining 10% of the incremental H_2S will be recovered in the new Sour Water Stripper overhead gas, which will be sent to the Jupiter facility.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]

This subchapter limits new gas-fired fuel-burning equipment with rated heat input greater than or equal to 50 MMBtu/hr to emissions of 0.20 lbs of NO_X per MMBtu, three-hour average. All of the new or modified heaters and boilers for this project will have $ULNO_X$ burners that limit NO_X emissions from 0.05 lb/MMBtu to 0.075 lb/MMBtu. Emissions limitations in the permit will be based on these NO_X specifications; therefore, the heaters and boilers will be in compliance with this subpart.

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]

The project does not involve the installation or modification of any of the following equipment: gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit. The facility is not located in, nor impacts, a nonattainment area.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]

Part 3 requires storage tanks constructed after December 28, 1974 with a capacity of 40,000 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to either be operated as a pressure vessel or be equipped with internal/external floating roofs or vapor recovery devices. The new ULSD tank for this project will be constructed in accordance with NSPS Subpart Kb, which will ensure compliance with Subchapter 37.

Part 7 requires VOC gases from a vapor recovery blowdown system to be burned by a smokeless flare or equally effective control device as approved by the Division Director. This project may involve new pressure relief devices routed to a flare that is in compliance with the provisions of this section.

Part 7 also requires fuel-burning and refuse-burning equipment to be operated to minimize emissions of VOC. All the combustion units are subject to this requirement.

Part 7 also requires all reciprocating pumps and compressors handling VOCs to be equipped with packing glands and rotating pumps and compressors handling VOCs to be equipped with mechanical seals. The new pumps and compressors will be subject to this requirement.

Part 7 also regulates VOC/water separators that receive water containing more than 200 gallons per day of VOC. Any new or existing waste water systems at the refinery are subject to NSPS Subpart QQQ, which contains standards more stringent than Part 7.

OAC 252:100-41 (Hazardous Air Pollutants and Toxic Air Contaminants) [Applicable]
Part 3 addresses hazardous air contaminants. NESHAP, as found in 40 CFR Part 61, are adopted by reference as they exist on July 1, 2003, with the exception of Subparts B, H, I, K, Q, R, T, W and Appendices D and E, all of which address radionuclides. In addition, General Provisions as found in 40 CFR Part 63, Subpart A, and the Maximum Achievable Control Technology (MACT) standards as found in 40 CFR Part 63, Subparts F, G, H, I, J, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, KK, LL, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, XX, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, QQQ, RRR, TTT, UUU, VVV, XXX, AAAA, CCCC, GGGG, HHHH, JJJJ, NNNN, OOOO, QQQQ, RRRR, SSSS, TTTT, UUUU, VVVV, WWWW, XXXX, BBBBB, CCCCC, FFFFF, JJJJJ, KKKKK, LLLLL, MMMMM, NNNNN, PPPPP, QQQQQ, and SSSSS are hereby adopted by reference as they exist on July 1, 2003. These standards apply to both existing and new sources of HAPs. These requirements are covered in the "Federal Regulations" section.
Part 5 is a **state-only** requirement governing toxic air contaminants. New sources (constructed after March 9, 1987) emitting any category "A" pollutant above de minimis levels must perform a BACT analysis, and if necessary, install BACT. All sources are required to demonstrate that emissions of any toxic air contaminant, which exceeds the de minimis level, do not cause or contribute to a violation of the maximum acceptable ambient concentration (MAAC). This subchapter provides an exemption for all HAPs that are subject to a NESHAP emission standard in 40 CFR Part 63. All other HAPs and/or toxics must be shown to be in compliance. HAP emissions from the refinery fugitive sources, miscellaneous process vents, wastewater systems, etc., are subject to standards in the Refinery MACT, 40 CFR Part 63, Subpart CC. As stated previously, emissions from the hydrogen plant deaerator vent are exempt from the Refinery MACT standards. Compliance with Subchapter 41 for emissions of methanol and ammonia from the hydrogen plant deaerator vent was demonstrated in Section VI above. No. 4 FCCU and No. 5 FCCU are subject to standards in the Refinery MACT II, 40 CFR Part 63, Subpart UUU, although compliance is not required until April 11, 2005.

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.

SECTION VIII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
PSD applies to this project. The PSD review is presented in Section V.

NSPS 40 CFR Part 60 [Subparts A, Db, J, Kb, GGG, and QQQ are Applicable]
Subpart A, General Provisions. This subpart requires the submittal of several notifications for NSPS-affected sources, which, for this project, are new/modified process heaters and boilers, a new storage tank, and new fugitive equipment. 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 permittee 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 set forth in Subpart A.

Subpart Db, Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units with a design capacity greater than 100 MMBtu/hr heat input and that commenced construction or modification after June 19, 1984. The new boilers, B-0009 and B-0010, have a combined heat input capacity of approximately 740 MMBtu/hr and are, therefore, subject to Subpart Db. The new hydrogen plant produces steam from process heaters as that term is defined in Subpart Db and, therefore, those process heaters are not subject to the subpart. Because boilers B-0009 and B-0010 are also subject to the sulfur dioxide standards under Subpart J, they are only subject to the particulate matter and nitrogen oxides standards of Subpart Db. The particulate matter standard is not applicable because the two boilers will be limited to natural gas as fuel. The nitrogen oxide limit for natural gas-fired boilers is 0.10 lb/MMBtu for low heat release and 0.20 lb/MMBtu for high heat release. Boilers B-0009 and B-0010 will be constructed with $ULNO_X$ burners with NO_X emissions based on 0.05 lb/MMBtu and, therefore, will be in compliance. Subpart Db also includes testing, reporting, and recordkeeping which will be a requirement of the permit.

Subpart J, Petroleum Refineries. This subpart affects the following facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and Claus sulfur recovery plants. Under the Consent Decree, the No. 4 FCCU and No. 5 FCCU regenerators are subject to the CO and SO_2 requirements of NSPS 40 CFR Part 60, Subpart J. The CO requirement for both FCCUs became effective on June 30, 2003, and the SO_2 requirement became effective on August 1, 2003 for the No. 4 FCCU and February 1, 2004 for the No. 5 FCCU. The permit will require that the No. 4 FCCU and No. 5 FCCU comply with all

applicable requirements and standards of Subpart J for CO and SO_2.

Subpart J specifies a limit of 0.10 gr/dscf for H_2S content in fuel gas burned in any fuel gas combustion device. A continuous monitoring device to measure either SO_2 emission concentration or H_2S concentration in the fuel gas must be installed. Subpart J also includes testing, reporting, and recordkeeping requirements. All of the new and modified process heaters and boilers for this project will be subject to Subpart J. In accordance with Paragraph 69 and Attachment 3 of Civil Action No. H-01- 4430(A), process heater H-5001 will be subject to Subpart J upon completion of the furnace modifications or December 31, 2006, whichever is later. The Ponca City South Plant and East Plant flares are subject to Subpart J. Compliance will be in accordance with 40 CFR §60.11(d) in lieu of the requirements of 40 CFR §60.104(a)(1) and as outlined in the options provided in Paragraph 156 of Civil Action No. H-01- 4430(A), including the procedures set forth in Paragraphs 183 through 188 of that same Consent Decree. These flares will be equipped with various control devices such as flare gas recovery systems, Sulfur Sorbers, and/or H_2S CEMS instrumentation to comply with 40 CFR §60.11(d).

Subpart Kb, Volatile Organic Liquids Storage Vessels. This subpart affects VOL storage vessels (including petroleum liquids storage vessels) for which construction, reconstruction, or modification commenced after July 23, 1984, and which have a capacity of 19,813 gallons (75 cubic meters) or more. 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 39,980 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 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 new ULSD tank will have a capacity of 100,000 bbl and is subject to this subpart. The tank will be constructed with an internal floating roof in compliance with this subpart. Monitoring, reporting, and recordkeeping will be a requirement of the permit.

Subpart GGG, Equipment Leaks of VOC in Petroleum Refineries. Subpart GGG affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service which commenced construction or modification after January 4, 1984, and which is located within a process unit in a petroleum refinery. The subpart defines "process unit" as "components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product." Any of the new equipment components for this project that are determined to contain less than 5% HAP will be incorporated into the refinery's existing leak detection and repair (LDAR) program. Equipment components with 5% or greater HAP content are subject to NESHAP 40 CFR Part 63, Subpart CC, which specifies more stringent control than NSPS Subpart GGG.

Subpart QQQ, VOC Emissions From Petroleum Refinery Wastewater Systems. This subpart affects refinery wastewater systems for which construction, reconstruction, or modification

commenced after May 4, 1987. This project will involve physical changes to individual drain systems in the form of new process drains and junction boxes. New drains installed as part of this project must be equipped with water seal controls and the applicant must comply with the monitoring, testing, recordkeeping, and reporting requirements of Subpart QQQ.

NESHAP 40 CFR Part 61 [Subpart FF is Applicable]
There are no emissions of any of the regulated pollutants: arsenic, asbestos, benzene, beryllium, coke oven emissions, mercury, radionuclides, or vinyl chloride, except for benzene.

Subpart J, Equipment Leaks of Benzene. This subpart applies to pumps, compressors, pressure relief devices, sampling connections, systems, open-ended valves or lines, valves, 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 for this project will be less than 10% by weight and is not intended to operate in benzene service. Therefore, Subpart J is not applicable to this project.

Subpart FF, Benzene Waste Operations. This subpart applies to waste streams at chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries that have benzene-containing hazardous waste treatment, storage, and disposal facilities. The benzene concentration for waste streams in each affected individual drain system is expected to be less than 10 ppmw for this project. Therefore, in accordance with 40 CFR 61.342(c)(2), the control requirements in this subpart are not applicable to these drain systems. However, the permittee must demonstrate initially and, thereafter, at least once per year that the flow-weighted annual average benzene concentration for the waste stream is less than 10 ppmw as determined by the procedures specified in 40 CRF 61.355(c)(2), knowledge of the waste, or 40 CRF 61.355(c)(3) protocol testing. Records of such determinations must be kept in accordance with 40 CFR 61.356.

NESHAP 40 CFR Part 63 [Subparts CC, UUU, and DDDDD are Applicable]
Subpart CC, Petroleum Refineries (Refinery MACT). This subpart affects petroleum refining process units and related emission points located at a plant site that is a major source as defined in section 112(a) of the Clean Air Act and emits or contacts one or more of the hazardous air pollutants listed in Table 1 of this subpart. The various emission units includes:

- miscellaneous process vents
- storage vessels
- wastewater streams and treatment operations
- equipment leaks
- gasoline loading racks
- marine vessel loading operations

This project involves the construction of miscellaneous process vents, a storage vessel, wastewater streams, and equipment leak components. The hydrogen plant deaerator vent, although a miscellaneous process vent, is exempt from the control standards in this subpart as explained in Section IV. The new ULSD storage tank will comply with 40 CFR Part 60 Subpart Kb; therefore, it will be in compliance with this subpart. Any new wastewater streams for this project are subject to this subpart. New valves, pumps, and associated components resulting from the project may be in organic HAP service and would be subject to the LDAR provisions of Subpart CC.

Subpart UUU, Petroleum Refineries – Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Plants (Refinery MACT II). This subpart affects the following:

- Process vents on each catalytic cracking unit that is associated with regeneration of the catalyst.
- Process vents on each catalytic reforming unit that is associated with regeneration of the catalyst.
- Process vents that vent from a Claus or other type of sulfur recovery plant unit or the tail gas treatment 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 (FCCUs) 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 for PM (§60.102) 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 for CO (§60.103) 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. 4 FCCU regenerator is currently not subject to NSPS Subpart J for PM, but will be subject by December 31, 2008 under the Consent Decree. The No. 5 FCCU regenerator is currently not subject to NSPS Subpart J for PM, but will be subject by December 31, 2006 under the Consent Decree. Both FCCUs are currently subject to NSPS Subpart J for CO per the Consent Decree and will, therefore, be in compliance with Subpart UUU for organic HAP emissions.

Subpart YYYY, Stationary Combustion Turbines. This subpart affects new and reconstructed stationary turbines constructed after January 14, 2003. This project will not involve the addition or modification of any turbines. Therefore, this subpart is not applicable.

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart was promulgated on February 26, 2004 and affects existing, new, and reconstructed spark ignition 4-stroke rich-burn (4SRB) RICE, new or reconstructed spark ignition 2-stroke lean-burn (2SLB) RICE, new or reconstructed 4-stroke lean-burn (4SLB) RICE, and new or reconstructed compression ignition (CI) RICE, with a site-rating greater than 500 brake horsepower, that are

located at a major source of HAP emissions. There are no new or reconstructed RICE as part of this project.

Subpart DDDDD, Industrial/Commercial/Institutional Boilers and Process Heaters. This subpart was published in the Federal Register on September 13, 2004, and affects new, reconstructed, and existing boilers and process heaters fired with solid, liquid, and gaseous fuels. All of the new process heaters and boilers included in this project are large units, defined as watertube boilers and process heaters with heat input capacities greater than 10 million British thermal units per hour (MMBtu/hr). All the new boilers and process heaters will be fired with natural gas, refinery fuel gas, and/or PSA offgas. Therefore, the new boilers and process heaters must meet the CO concentration standard of 400 ppmdv corrected to 3% oxygen. Two of the new process heaters, NH-6007 and ULSD-5/5a, and the two new boilers, B-0009 and B-0010, have heat input capacities greater than 100 MMBtu/hr and are required to use CO continuous emission monitors (CEMS) to demonstrate that average CO emissions, on a 30-day rolling average, are equal to or less than the CO standard. The heat input capacities of the remaining new process heaters, H-1001, H-9901 and H-9902, are less than 100 MMBtu/hr and are required to conduct initial and annual compliance tests to demonstrate compliance with the CO standard. The permittee will also be required to meet the testing, monitoring, and recordkeeping requirements of this subpart. None of the modified process heaters included in this project, H-6014, H-6015, H-5001, H-0057, H-0058, and H-0059, will be reconstructed as that term is defined in paragraph §63.7490 and, therefore, are only subject to the initial notification requirements of this subpart.

CAM, 40 CFR Part 64 [Not Applicable]

Compliance Assurance Monitoring (CAM) 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 of 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.
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY of a criteria pollutant, 10 TPY of an individual HAP, or 25 TPY of total HAPs.

The new and modified process heaters and boilers for this project will have a control device, i.e., $ULNO_X$ burners, but none of the individual heaters or boilers have the potential to emit more than 100 TPY of NO_X. Therefore, CAM is not applicable to this project.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]

This facility will not process or store more than the threshold quantity of any regulated substance (Section 112r of the Clean Air Act 1990 Amendments). More information on this federal program is available on the web page: *www.epa.gov/ceppo*.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subpart A and F 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.

Conditions are included in the permit to address the recordkeeping requirements specified at §82.13 of this regulation. Recordkeeping requirements specific to manufacturing facilities include those for importers of Class I substances, or for persons who destroy Class I controlled substances.

SECTION IX. COMPLIANCE

Tier Classification and Public Review

Permit Modification (M-1)

This application has been determined to be Tier I based on the request for a minor modification to a previously issued construction permit for a significant modification of a Part 70 permit as defined in OAC 252:100-8-7.2(b)(1)(A). This determination was based on the fact that this modification:

1. Will not violate any applicable requirements.
2. Will not involve relaxation or removal of current monitoring, reporting, or recordkeeping requirements.
3. Does not require 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. The previous BACT analysis, ambient air impact analysis, and increment analysis are all unchanged.
4. Does not establish or change a permit term or condition, for which there is no underlying applicable requirement or state-only requirement, to avoid some other applicable requirement or state-only requirement.
5. Is not considered a modification under NSPS, PSD, or NESHAP.

The permit was submitted to EPA for a 45-day comment period. No comments were received.

Information on all permit actions is available for review on the Air Quality section of the DEQ web page at *http://www.deq.state.ok.us*.

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 real property.

Permit No. 2003-336-C PSD

This application was determined to be Tier II based on the request for a construction permit for a Part 70 source for a facility change that is considered a significant modification as defined in OAC 252:100-8-7.2(b)(2)(A).

The applicant published the "DEQ Notice of Filing a Tier II Application" in the *Ponca City News*, a daily newspaper in Kay County, on November 7, 2003. The notice stated that the application was available for public review at the Ponca City Library, located at 515 E. Grand Ave., Ponca City, Oklahoma, or at the AQD main office.

The applicant requested, and EPA Region VI agreed, to conduct the EPA 45-day permit review concurrent with the 30-day public review of the draft permit. A copy of the draft permit was sent to EPA Region VI and a letter was sent to the State of Kansas advising them of the availability of the draft permit. No comments were received from the EPA or the State of Kansas.

The applicant published a "Notice of Tier II Draft Permit and Public Meeting" in the *Ponca City News* on June 30, 2004. The notice stated that a copy of the draft copy was available for public review at the Ponca City Library and at the AQD main office. The notice also stated that a public meeting on the permit modification would be held at 6:30 p.m. on August 11, 2004, at the Pioneer Technology Center at 2101 N. Ash, Room B-134, Ponca City, Oklahoma. Dave Dillon of AQD Customer Services Division and Grover Campbell, permit writer, attended the public meeting on August 11, 2004. No public comments were received during the 30-day public review or during the public meeting.

Fees Paid

A permit fee of $1,500 for a modification of a Part 70 source construction permit has been paid.

SECTION X. SUMMARY

The applicant has demonstrated the ability to achieve compliance with the applicable air quality rules and regulations. Ambient air quality standards are not threatened at the site. There are no active Air Quality compliance or enforcement actions that would prevent issuance of this permit. Issuance of the permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

ConocoPhillips Company
Ponca City Refinery
Ultra-Low Sulfur Diesel Project **Permit No. 2003-336-C (M-1) PSD**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on November 4, 2003, and modifications submitted on September 9, 2004. The Evaluation Memorandum dated December 17, 2004, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction or operations under this permit constitutes acceptance of, and consent to, the conditions contained herein:

1. **Points of emission, emission limitations, and standards** [OAC 252:100-8-6(a)]

A. Heaters and Reboilers – ULSD, No. 3 CRU

Emission Unit	Pollutant	Emissions	
		lb/hr *	TPY *
H-1001, No. 4 HDT Heater	NO_X	1.50	6.6
	SO_2	1.23	5.4
	CO	1.20	5.3
	VOC	0.16	0.7
	PM_{10}	0.23	1.0
H-9901, No. 9 HTD Heater	NO_X	2.00	8.8
	SO_2	1.64	7.2
	CO	1.60	7.0
	VOC	0.22	1.0
	PM_{10}	0.30	1.3
H-9902, No. 9 HDT Stripper Reboiler	NO_X	2.50	11.0
	SO_2	2.05	9.0
	CO	2.00	8.8
	VOC	0.27	1.2
	PM_{10}	0.37	1.6
ULSD-5/5a, Hydrogen Plant Reformer	NO_X	21.2	92.8
	SO_2	11.6	50.8
	CO	11.3	49.5
	VOC	1.52	6.7
	PM_{10}	2.12	9.3
NH-6007, No. 3 CRU Reformer Main Furnace	NO_X	8.75	38.3
	SO_2	7.18	31.4
	CO	7.00	30.7
	VOC	0.94	4.1
	PM_{10}	1.31	5.7

* 365-day rolling average.

i. H-1001, H-9901, H-9902, NH-6007, and ULSD-5/5a are subject to 40 CFR Part 60, Subpart J and shall comply with all applicable requirements and standards, including but

not limited to: [40 CFR Part 60]

a. §60.104 Standards for sulfur oxides. H-1001, H-9901, H-9902, NH-6007, and ULSD-5/5a shall combust only pipeline grade natural gas, PSA offgas, or refinery fuel gas with a 3-hour rolling average maximum H_2S concentration of 0.10 gr/dscf (160 ppmv @ 60°F).
b. §60.105 Monitoring of emissions and operations. A continuous monitoring system shall be operated and maintained to record H_2S content of the fuel gas.
c. §60.106 Test methods and procedures
d. §60.107 Reporting and recordkeeping requirements
e. §60.108 Performance test and compliance provisions

ii. Compliance of H-1001, H-9901, H-9902, NH-6007, and ULSD-5/5a with the SO_2 emission limits of Specific Condition 1.A shall be based on a 365-day rolling average fuel gas usage and H_2S content and shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula:

$$SO_2, \text{TPY} = \frac{\text{MMSCFD} * \text{ppmvd } H_2S * 64 \text{ lb } SO_2/\text{lb-mole} * 365 \text{ days/year}}{2000 \text{ lb/ton} * 379.4 \text{ Scf/lb-mole}}$$

iii. H-1001, H-9901, H-9902, and NH-6007 shall be constructed with burners with NO_X emissions limited to no greater than 0.050 lb/MMBtu (HHV), 365-day rolling average. [OAC 252:100-8-6(a)]

iv. ULSD-5/5a shall be constructed with burners with NO_X emissions limited to no greater than 0.075 lb/MMBtu (HHV), 365-day rolling average. [OAC 252:100-8-6(a)]

v. Compliance of H-1001, H-9901, H-9902, NH-6007, and ULSD-5/5a with the NO_X and CO annual emission limits shall be based on a 365-day rolling average fuel gas usage and heater specific (stack test) emission factors, when available, or the most current version emission factors from AP-42 Table 1.4-1. Compliance shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula:

$$\text{TPY} = \frac{\text{MMSCFD} * \text{Btu/Scf (HHV)} * \text{EF} * 365 \text{ days/year}}{2000 \text{ lb/ton}}$$

where EF = Emission Factor, lb/MMBtu

vi. H-1001, H-9901, H-9902, NH-6007, and ULSD-5/5a shall be operated using good combustion practices to comply with the emission limitations of VOC and PM_{10}. [OAC 252:100-8-6(a)]

vii. H-1001, H-9901, H-9902, NH-6007, and ULSD-5/5a are subject to NESHAP 40 CFR Part 63, Subpart DDDDD and shall comply with all applicable requirements and standards including, but not limited to:

a. §63.7499-§63.7500 Emission Limits and Work Practice Standards. H-1001, H-9901, H-9902, NH-6007, and ULSD-5/5a shall comply with a CO concentration limit of 400 ppm by volume on a dry basis corrected to 3% oxygen. H-1001, H-9901, and H-9902 compliance with the CO emission standard will be based on a 3-run average performance test. NH-6007 and ULSD-5/5a compliance with the CO emission standard will be based on a 30-day rolling average.
b. §63.7510-§63.7530 Testing and Initial Compliance. H-1001, H-9901, and H-9902 shall conduct an initial performance test and an annual performance test per procedures in §63.7520 to demonstrate compliance with the CO emission standard.
c. §63.7535-§63.7541 Continuous Compliance. NH-6007 and ULSD-5/5a shall install, operate, and maintain a continuous emission monitoring system (CEMS) for carbon monoxide.
d. §63.7545-§63.7560 Notifications, Reports, and Records.

viii. Within 60 days of achieving maximum firing rate from the heaters/reboilers, not to exceed 180 days from initial start-up, and at other such times as directed by Air Quality, the permittee shall, for each heater, 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:

a. Method 1: Sample and Velocity Traverses for Stationary Sources.
b. Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.
c. Method 3 or 3A: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight
d. Method 4: Determination of Moisture in Stack Gases.
e. Method 7E: Determination of Nitrogen Oxide Emissions From Stationary Sources.
f. Method 10: Determination of Carbon Monoxide Emissions From Stationary Sources.
g. Method 19: F-factor Methodology

ix. Performance testing for NO_X and CO shall be conducted while a process heater is operating within 10% of its maximum design firing rate, except for those process heaters that cannot be fired within 10% of the maximum design firing rate due to process limitations and/or production limitations. In those cases, the permittee shall conduct an initial performance test at the maximum firing rate possible under the present operating conditions and within the time guidelines given above. The permittee shall include in the written performance test report submitted to Air Quality the reasons for testing the process heater at less than 90% of the maximum design firing rate. The permittee shall then conduct testing of the process heater at least once per calendar quarter 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. The permittee shall submit the results of quarterly tests to AQD. Within 60 days of achieving 90% or more of maximum firing rate, the permittee shall conduct performance testing using the test methods specified in 40 CFR Part 60 and furnish a written report to Air Quality documenting compliance with emission limitations. If the second performance test demonstrates that the process heater is in compliance with all emission limitations, no additional quarterly testing will be required. 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.

B. Heaters and Reboilers – No. 2 CTU, No. 5 FCCU, Alky

Emission Unit	Maximum Firing Rate, MMBtu/hr (HHV)	Pollutant	Emissions	
			lb/hr [A]	TPY [A]
H-6014, No. 2 CTU Preflash Tower Reboiler	71	NO_X	3.55	15.5
		SO_2	2.91	12.8
		CO	2.84	12.4
		VOC	0.38	1.7
		PM_{10}	0.53	2.3
H-6015, No. 2 CTU Vacuum Tower Furnace	130	NO_X	6.50	28.5
		SO_2	5.33	23.3
		CO	5.20	22.8
		VOC	0.70	3.1
		PM_{10}	0.98	4.3
H-5001, No. 5 FCCU Feed Preheater	104	NO_X	5.20	22.8
		SO_2	4.26	18.7
		CO	4.16	18.2
		VOC	0.56	2.5
		PM_{10}	0.78	3.4
H-0057, H-0058, and H-0059 Alky Depropanizer Reboilers [B]	189	NO_X	9.45	41.3
		SO_2	7.75	34.0
		CO	7.56	33.2
		VOC	1.02	4.6
		PM_{10}	1.43	6.2

A. 365-day rolling average.
B. All three heaters share a common stack.

i. Compliance of H-6014, H-6015, H-5001, H-0057, H-0058, and H-0059 with the firing rate limits of Specific Condition 1.B shall be based on 365-day rolling average fuel gas usage and heating values and shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula:

MMBtu/hr = MMSCFD * Btu/Scf (HHV) * (1 day/24 hours) * ($1/10^6$)

ii. Upon issuance of this permit, H-6014, H-6015, H-0057, H-0058, and H-0059 are subject to 40 CFR Part 60, Subpart J and shall comply with all applicable requirements and standards, including but not limited to: [40 CFR Part 60]

a. §60.104 Standards for sulfur oxides. H-6014, H-6015, H-5001, H-57, H-58, and H-59 shall combust only pipeline grade natural gas or refinery fuel gas with a 3-hour rolling average maximum H_2S concentration of 0.1 gr/dscf (160 ppmv @ 60°F).
b. §60.105 Monitoring of emissions and operations. A continuous monitoring system shall be operated and maintained to record H_2S content of the fuel gas.
c. §60.106 Test methods and procedures
d. §60.107 Reporting and recordkeeping requirements
e. §60.108 Performance test and compliance provisions

iii. Upon completion of modification, H-5001 will be subject to 40 CFR Part 60, Subpart J and shall comply with all applicable requirements and standards, including but not limited to: [Civil Action H-01-4430 and 40 CFR Part 60]

a. §60.104 Standards for sulfur oxides. H-5001 shall combust only pipeline grade natural gas or refinery fuel gas with a 3-hour rolling average maximum H_2S concentration of 0.1 gr/dscf (160 ppmv @ 60°F).
b. §60.105 Monitoring of emissions and operations. A continuous monitoring system shall be operated and maintained to record H_2S content of the fuel gas.
c. §60.106 Test methods and procedures
d. §60.107 Reporting and recordkeeping requirements
e. §60.108 Performance test and compliance provision

iv. Compliance of H-6014, H-6015, H-5001, H-0057, H-0058, and H-0059 with the SO_2 emission limits of Specific Condition 1.B shall be based on 365-day rolling average fuel gas usage and H_2S content and shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula:

$$SO_2, \text{TPY} = \frac{\text{MMSCFD} * \text{ppmvd } H_2S * 64 \text{ lb } SO_2/\text{lb-mole} * 365 \text{ days/year}}{2000 \text{ lb/ton} * 379.4 \text{ Scf/lb-mole}}$$

v. H-6014, H-6015, H-5001, H-0057, H-0058, and H-0059 shall be modified to include burners with NO_X emissions limited to no greater than 0.050 lb/MMBtu (HHV) on a 365-day rolling average basis. [Civil Action H-01-4430]

vi. Upon completion of modification, CO emissions for H-6014, H-6015, H-5001, H-0057, H-0058, and H-0059 shall not exceed 0.060 lb/MMBtu (HHV), on a 24-hour rolling average basis, and 0.040 lb/MMBtu (HHV) on a 365-day rolling average basis. [Civil Action H-01-4430]

vii. Compliance of H-6014, H-6015, H-5001, H-0057, H-0058, and H-0059 with the NO_X and CO emission limits of Specific Condition 1.B shall be based on 365-day rolling average fuel gas usage and heater specific (stack test) emission factors, when available, or the most current version emission factors from AP-42 Table 1.4-1. Compliance shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula:

$$\text{TPY} = \frac{\text{MMSCFD} * \text{Btu/Scf (HHV)} * \text{EF} * 365 \text{ days/year}}{2000 \text{ lbs/ton}}$$

where EF = Emission Factor, lb/MMBtu

viii. H-6014, H-6015, H-5001, H-0057, H-0058, and H-0059 shall be operated using good combustion practices to comply with the emission limitations of VOC and PM_{10}.

[OAC 252:100-8-6(a)]

ix. H-6014, H-6015, H-5001, H-0057, H-0058, and H-0059 are subject to the initial notification requirements in 40 CFR §63.9(b) for compliance with NESHAP 40 CFR Part 63, Subpart DDDDD.

x. Within 180 days of commencement of operation of the $ULNO_X$ burners installed in heaters H-6015 and H-5001, the permittee shall, for each of the two heaters, do one (either option a or b) of the following:

a. Install, or continue to operate, NO_X and CO Continuous Emission Monitoring Systems (CEMS).
b. Use or develop approved NO_X and CO Parametric Emissions Monitoring Systems (PEMS).

[Civil Action H-01-4430]

xi. Within 180 days of commencement of operation of the $ULNO_X$ burners installed in heaters H-6015 and H-5001, the permittee shall, for each of the two heaters, do one (either option a or b) of the following:

a. If the permittee selects option b of Specific Condition 1.B.x, conduct performance testing 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

b. If the permittee selects option a of Specific Condition 1.B.x, certify, calibrate, maintain, and operate NO_X and CO Continuous Emissions 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 §§ 5.1.1, 5.1.3, and 5.1.4, ConocoPhillips 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.

[Civil Action H-01-4430]

xii. Within 180 days of commencement of operation of the $ULNO_X$ burners installed in heater H-6014, the permittee shall, for each of the four heaters, 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:

a. Method 1: Sample and Velocity Traverses for Stationary Sources.
b. Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.
c. Method 3 or 3A: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
d. Method 4: Determination of Moisture in Stack Gases.
e. Method 7E: Determination of Nitrogen Oxide Emissions From Stationary Sources.
f. Method 10: Determination of Carbon Monoxide Emissions From Stationary Sources.
g. Method 19: F-factor Methodology.

[Civil Action H-01-4430]

xiii. Performance testing for NO_X and CO shall be conducted while the units are operating within 10% of the maximum design firing rates.

xiv. Within 180 days of commencement of operation of the $ULNO_X$ burners installed in heaters H-0057, H-0058, and H-0059, the permittee shall install, certify, calibrate, maintain, and operate a NO_X and CO Continuous Emissions Monitoring System (CEMS) in the common stack for the three heaters, 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 §§ 5.1.1, 5.1.3, and 5.1.4, ConocoPhillips 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. [Civil Action H-01-4430]

xv. This specific condition shall supercede the limitations for H-0057 and H-0058 included in Specific Condition 1 of Permit No. 91-043-O (M-5).

C. Boilers

Emission Unit	Pollutant	Emissions	
		lb/hr [A]	TPY [A]
B-9 and B-10 Boilers [B]	NO_X	36.8	161
	SO_2	30.0	131
	CO	29.4	129
	VOC	3.96	17.4
	PM_{10}	5.52	24.2

A. 365-day rolling average.
B. Boilers share a common stack.

i. B-9 and B-10 are subject to 40 CFR 60, Subpart J and shall comply with all applicable requirements including, but not limited to:

a. §60.104 Standards for sulfur oxides. B-9 and B-10 shall combust only pipeline grade natural gas or refinery fuel gas with a 3-hour rolling average maximum H_2S concentration of 0.1 gr/dscf (160 ppmv @ 60ºF).
b. §60.105 Monitoring of emissions and operations. A continuous monitoring system shall be operated and maintained to record H_2S content of the fuel gas.
c. §60.106 Test methods and procedures
d. §60.107 Reporting and recordkeeping requirements
e. §60.108 Performance test and compliance provisions

ii. Compliance of B-9 and B-10 with the SO_2 emission limits of Specific Condition 1.C shall be based on 365-day rolling average fuel gas usage and H_2S content and shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula:

$$SO_2 \text{ TPY} = \frac{\text{MMSCFD} * \text{ppmvd } H_2S * 64 \text{ lb } SO_2/\text{lb-mole} * 365 \text{ days/year}}{2000 \text{ lb/ton} * 379.4 \text{ Scf/lb-mole}}$$

iii. B-9 and B-10 shall be constructed with burners with NO_X emissions limited to no greater than 0.050 lb/MMBtu, 365-day rolling average. [OAC 252:100-8-6(a)]

iv. Compliance of B-9 and B-10 with the NO_X and CO emission limits of Specific Condition 1.C shall be based on 365-day rolling average fuel gas usage and heater specific (stack test) emission factors, when available, or the most current version emission factors from AP-42 Table 1.4-1. Compliance shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula:

$$\text{TPY} = \frac{\text{MMSCFD} * \text{Btu/Scf (HHV)} * \text{EF} * 365 \text{ days/year}}{2000 \text{ lb/ton}}$$

where EF = Emission Factor, lb/MMBtu

v. Each of the sources shall be operated using good combustion practices to comply with the emission limitations of VOC and PM_{10}. [OAC 252:100-8-6(a)]

vi. B-9 and B-10 are subject to 40 CFR 60, Subpart Db and shall comply with all applicable requirements including, but not limited to:

a. §60.44b Standards for nitrogen oxides
b. §60.46b Performance test and compliance provisions
c. §60.48b Monitoring of emissions
d. §60.49b Reporting and recordkeeping requirements

vii. B-9 and B-10 are subject to NESHAP 40 CFR Part 63, Subpart DDDDD and shall

comply with all applicable requirements and standards including, but not limited to:

a. §63.7499-§63.7500 Emission Limits and Work Practice Standards. B-9 and B-10 shall comply with a CO concentration limit of 400 ppm by volume on a dry basis corrected to 3% oxygen based on a 30-day rolling average.
b. §63.7510-§63.7530 Testing and Initial Compliance.
c. §63.7535-§63.7541 Continuous Compliance. B-9 and B-10 shall install, operate, and maintain a continuous emission monitoring system (CEMS) for carbon monoxide.
d. §63.7545-§63.7560 Notifications, Reports, and Records.

viii. Within 60 days of achieving maximum firing rate from the boilers, not to exceed 180 days from initial start-up, 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:

a. Method 1: Sample and Velocity Traverses for Stationary Sources.
b. Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.
c. Method 3 or 3A: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight
d. Method 4: Determination of Moisture in Stack Gases.
e. Method 7E: Determination of Nitrogen Oxide Emissions From Stationary Sources.
f. Method 10: Determination of Carbon Monoxide Emissions From Stationary Sources.
g. Method 19: F-factor Methodology.

ix. Performance testing for NO_X and CO shall be conducted while the units are operating within 10% of the maximum design firing rates. For purposes of demonstrating compliance with 40 CFR 60, Subpart Db, boilers B-9 and B-10 may be operated individually or as a single unit during performance testing.

D. Fluidized Catalytic Cracking Units (FCCU)

Emission Unit	Pollutant	PPMDV	Emissions	
			lb/hr [1]	TPY [1]
No. 4 FCCU	CO	500 [2] / 150 [3]	83.7 [4]	110 [5]
	PM_{10}	na [6]	33.1	145
	NO_X	na [6]	19.9	87
	SO_2	na [6]	76.0	333
	VOC	na [6]	1.9	8.3
No. 5 FCCU/ B-5004	CO	500 [2] /150 [3]	160 [4]	25.1 [5]
	PM_{10}	na [6]	27.5	120
	NO_X	na [6]	26.4	116
	SO_2	50 [7] / 25 [8]	58.7	257

1. 365-day rolling average, except as noted.
2. ppmdv @ 0% oxygen, 1-hour average. [Civil Action H-01-4430]
3. ppmdv @ 0% oxygen, 365-day rolling average. [Civil Action H-01-4430]
4. Corresponds to 500 ppmdv @ 0% oxygen, 1-hr average.
5. Corresponds to 150 ppmdv @ 0% oxygen, 365-day rolling average.

6. Not applicable, no ppm emission limitations established.
7. ppmdv @0% oxygen, 7-day rolling average. [Civil Action H-01-4430]
8. ppmdv @0% oxygen, 365-day rolling average. [Civil Action H-01-4430]

i. The CO and VOC emission concentration and rate limits of this specific condition shall be effective upon issuance of this permit and shall supercede the CO and VOC emission limits included in Specific Condition 1.A of Permit No. 2000-206-C (M-4) for the No. 4 FCCU and the CO emission limits included in Specific Condition 1.A of Permit No. 98-169-C (M-5) for the No. 5 FCCU. For the No. 4 FCCU, following completion of the modification project, the PM_{10}, NO_X, and SO_2 emission limits of this specific condition shall supercede the PM_{10}, NO_X, and SO_2 emission limits included in Specific Condition 1.A, and the NO_X and SO_2 limits in Specific Condition 5, of Permit No. 2000-206-C (M-4). For the No. 5 FCCU, once the SNCR and wet scrubber for the No. 5 FCCU are installed and operational, the PM_{10}, NO_X, and SO_2 emission concentration and rate limits of this specific condition shall supercede the PM_{10}, NO_X, and SO_2 emission limits included in Specific Condition 1.A, and the NO_X and SO_2 limits in Specific Condition 5, of Permit No. 98-169-C (M-4).

ii. Compliance with the annual limits shall be demonstrated monthly and be based on a 365-day rolling average.

iii. Compliance with the No. 4 FCCU PM_{10} emission limits of Specific Condition 1.D shall be based on a correlation for calculating PM_{10} from other measurable process variables, such as, but not limited to, opacity or superficial velocity. The correlation shall be developed from the No. 4 FCCU testing conducted on March 28, 2002 and May 20 and 21, 2003. This specific condition supercedes Specific Condition 12 of Permit No. 2000-206-C (M-4).

E. Fugitive Components

Emission Unit	Estimated Number of Components [1, 3]
ULSD	
Gas Valves	220
Light Liquid Valves	40
Heavy Liquid Valves	1280
Flanges	6160
Light Liquid Pumps	4
Heavy Liquid Pumps	44
Gas Compressors	4
Gas Relief Valves To Flare	20
Sample Stations	16
Controlled Process Drains	50
Junction Boxes	15
Saturated Gas Plant and Fire Rebuild	
Gas Valves	-4

Emission Unit	Estimated Number of Components [1, 3]
Light Liquid Valves	35
Heavy Liquid Valves	-2
Flanges	73
Heavy Liquid Pumps	-1
Process Drains (Controlled)	-1
No. 2 CTU	
Light Liquid Valves	20
Heavy Liquid Valves	20
Flanges	100
Heavy Liquid Valves	4
No. 3 CRU	
Gas Valves	25
Light Liquid Valves	25
Flanges	180
No. 4 FCCU [2]	
Gas Valves	307
Light Liquid Valves	12
Flanges	145
Gas Compressors	3
Gas Relief Valves To Flare	2
Sample Stations	1
Controlled Process Drains	11
No. 5 FCCU [2]	
Gas Valves	313
Light Liquid Valves	24
Heavy Liquid Valves	12
Flanges	277
Light Liquid Pumps	4
Heavy Liquid Pumps	4
Gas Compressors	3
Gas Relief Valves To Flare	2
Sample Stations	4
Controlled Process Drains	11
HF Alkylation Unit	
Gas Valves	12
Light Liquid Valves	18
Flanges	105
Light Liquid Pumps	2
Sample Stations	2

1. Equipment counts and emissions for equipment leaks associated with the projects included in this permit are estimates only and are included solely for the purposes of documenting regulatory applicability. The exact counts and emissions 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 program as specified in the following permit conditions.

2. Includes estimated number of components for Flare Gas Recovery Unit (FGRU).
3. Net change of components.

i. NESHAP 40 CFR Part 63, Subpart CC applies to the following affected equipment: each compressor, valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connection in HAP service. The permittee shall comply with the applicable sections for each affected component.

a. §63.642 General Standards
b. §63.648 Equipment Leak Standards
c. §63.654 Reporting and Recordkeeping Requirements

ii. Equipment determined to not be in HAP service (<5% by weight HAP) is subject to NSPS 40 CFR Part 60, Subpart GGG, and shall comply with all applicable requirements, including but not limited to:

a. §60.592 Standards
b. §60.593 Exceptions

iii. NESHAP 40 CFR Part 61, Subpart FF applies to the process sewer system in benzene service. The permittee shall comply with all applicable standards, including but not limited to:

a. §61.346 Standards: Individual drain systems
b. §61.349 Standards: Closed vent systems and control devices
c. §61.350 Standards: Delay of repair
d. §61.353 Alternative means of emission limitation
e. §61.354 Monitoring of operations
f. §61.355 Test methods, procedures, and compliance provisions
g. §61.356 Record keeping requirements
h. §61.357 Reporting requirements

iv. NSPS 40 CFR Part 60, Subpart QQQ applies to individual drain systems and aggregate facilities for process water collection and treatment. The permittee shall comply with all applicable standards, including but not limited to:

a. §60.692-2 Standards: Individual drain systems
b. §60.692-3 Standards: Oil-water separators
c. §60.692-5 Standards: Closed vent systems and control devices
d. §60.692-6 Standards: Delay of repair
e. §60.692-7 Standards: Delay of Compliance
f. §60.693-1 Alternative standards for individual drain systems
g. §60.694 Permission to use alternative means of emission limitations
h. §60.696 Test methods, procedures, and compliance provisions
i. §60.697 Recordkeeping requirements
j. §60.698 Reporting requirements

F. Cooling Tower

There are no emission limitations for the cooling tower. The permittee shall comply with the following requirements.

i. The cooling tower shall be constructed with drift eliminators.

ii. The permittee shall monitor the water flow through the cooling tower.

iii. The permittee shall implement a Monitoring, Inspection, and Maintenance Plan (MIMP) that includes monitoring of VOC in the cooling water return lines at least once per month, identification of VOC leaks, and repair of such leaks at the earliest opportunity, but no later than the next scheduled unit shutdown.

iv. The permittee shall maintain all results of monitoring and maintenance activities for a period of two years.

G. Tanks

Parameter	**Emission Unit**
	T-1101
Contents	Hydrocarbons
Capacity, barrels	100,000
Vapor Pressure, psia *	11.0
Annual Throughput, gallons	168,000,000
Design	Internal Floating Roof

* 365-day rolling average

i. The listed tank shall only store hydrocarbon liquids with vapor pressures less than or equal to the maximum indicated and be designed with internal floating roofs or equivalent.

ii. Total annual throughput shall be limited as indicated. Compliance shall be determined monthly and be based on 365-day rolling totals.

iii. Available Reid vapor pressure data and the maximum expected storage temperature based on the highest expected calendar month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs included in API Bulletin 2517.

iv. The tank is subject to NSPS 40 CFR Part 60, Subpart Kb and shall comply with all applicable standards including but limited to and except as provided in NESHAP CFR 40 §63.640(n)(8):

a. The owner or operator shall visually inspect the floating roof, the primary seal, the secondary seal (if present), gaskets, slotted membranes (if present), and sleeve seals

(if present) each time the storage vessel is emptied and degassed. If the floating roof has defects, the seals have holes, tears, or other openings in the seal or seal fabric; or the gaskets no longer close off the liquid surface from the atmosphere; or the slotted membrane has more than 10% open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exists before refilling the storage vessel with volatile organic liquid (VOL). In no event shall inspections conducted in accordance with this provision occur at intervals greater than five (5) years.

b. The owner or operator shall notify the AQD in writing at least 30 days prior to filling or refilling of this storage vessel for which inspection is required by 40 CFR 60.113b(a)(5) to afford AQD an opportunity to have an observer present. If the inspection is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the AQD at least seven days prior to refilling the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent so that it is received by the AQD at least seven days prior to refilling.

c. The owner or operator of these storage vessels shall keep records and furnish reports as required by 40 CFR 60.115b(a).

v. The owner or operator shall maintain a record of the volatile organic liquid stored, the period of storage and the maximum true vapor pressure of that VOL during the respective storage period for each tank. Copies of these records shall be retained on location for at least five years after the dates of recording. Available data on the storage temperature may be used to determine the maximum true vapor pressure. For crude oil or refined petroleum products, available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517.

vi. The tank is subject to NESHAP 40 CFR Part 63, Subpart CC and shall comply with all applicable requirements, including but not limited to:

a. §63.640 Applicability
b. §63.646 Storage Vessel Provisions
c. §63.654 Reporting and Recordkeeping

H. Flares

The South Plant and East Plant flares are subject to NSPS 40 CFR Part 60, Subpart J. Compliance will be in accordance with 40 CFR 60.11(d) in lieu of the requirements of 40 CFR 60.104(a)(1) and as outlined in the options provided in Paragraph 156 of Civil Action No. H-01-4430(A) including the procedures set forth in paragraphs 183 through 188 of that same Consent Decree. The East Plant and South Plant flares shall comply with 40 CFR 60.11(d) through implementation of equipment and/or instrumentation that support good air pollution control practices as approved by EPA.

2. The permittee shall be authorized to operate the listed equipment continuously (24 hours per day, every day of the year). [OAC 252:100-8]

3. The permittee shall update the Title V application within 180 days of start-up to incorporate the requirements of this permit. [OAC 252:100-8]

4. The permittee shall keep records of compliance as specified in Specific Condition No. 1. These records shall be made available to regulatory personnel upon request. Required records shall be retained on location for a period of at least five (5) years following dates of recording. [OAC 252:100-43]

5. 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 252:100-7 Permits for Minor Facilities
b. OAC 252:100-11 Alternative Emissions Reduction
c. OAC 252:100-15 Mobile Sources
d. OAC 252:100-39 Nonattainment Areas

6. This permit supercedes Permit No. 2003-336-C PSD, which is now null and void.

TITLE V (PART 70) PERMIT TO OPERATE / CONSTRUCT
STANDARD CONDITIONS
(October 15, 2003)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with Title V of the federal Clean Air Act (42 U.S.C. 7401, et seq.) 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, for revocation of the approval to operate under the terms of this permit, or for denial of an application to renew this permit. All applicable requirements (excluding state-only requirements) are enforceable by the DEQ, by EPA, and by citizens under section 304 of the Clean Air Act. This permit is valid for operations only at the specific location listed.
[OAC 252:100-8-1.3 and 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. [OAC 252:100-8-6 (a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from emergency conditions and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV. [OAC 252:100-8-6 (a)(3)(C)(iii)]

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. Oral notifications (fax is also acceptable) shall be made to the AQD central office as soon as the owner or operator of the facility has knowledge of such emissions but no later than 4:30 p.m. the next working day the permittee becomes aware of the exceedance. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. Every written report submitted under this section shall be certified by a responsible official.
[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (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), 8-6 (c)(1), and 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 as 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, 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. [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 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.

F. Submission of quarterly or semi-annual reports required by any applicable requirement that are duplicative of the reporting required in the previous paragraph will satisfy the reporting requirements of the previous paragraph if noted on the submitted report.

G. Every report submitted under this section shall be certified by a responsible official.

[OAC 252:100-8-6 (a)(3)(C)(iv)]

H. Any owner or operator subject to the provisions of NSPS shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility or any malfunction of the air pollution control equipment. [40 CFR 60.7 (b)]

I. Any owner or operator subject to the provisions of NSPS shall maintain a file of all measurements and other information required by the subpart recorded in a permanent file suitable for inspection. This file shall be retained for at least two years following the date of such measurements, maintenance, and records. [40 CFR 60.7 (d)]

J. 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 preventative or corrective measures adopted. [OAC 252:100-8-6 (c)(4)]

K. All testing must be conducted by methods approved by the Division Director under the direction of qualified personnel. All tests shall be made and the results calculated in accordance with

standard test procedures. The permittee may request the use of alternative test methods or analysis procedures. The AQD shall approve or disapprove the request within 60 days. 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]

L. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 CFR Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-4-5 and OAC 252:100-41-15]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original 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. 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)(A), (C)(v), and (D)]

B. The 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; and a statement that the facility will continue to comply with all applicable requirements.

[OAC 252:100-8-6 (c)(5)(C)(i)-(iv)]

C. Any document required to be submitted in accordance with this permit shall be certified as being true, accurate, and complete by a responsible official. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the certification 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 listed in the Evaluation Memorandum and 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, -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 10 days after such date.
[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, 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 as necessary to remedy deficiencies 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 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.

C. If "grandfathered" status is claimed and granted for any equipment covered by this permit, it shall only apply under the following circumstances: [OAC 252:100-5-1.1]

(1) It only applies to that specific item by serial number or some other permanent identification.
(2) Grandfathered status is lost if the item is significantly modified or if it is relocated outside the boundaries of the facility.

D. To make changes other than (1) those described in Section XVIII (Operational Flexibility), (2) administrative permit amendments, and (3) those not defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII), the permittee shall notify AQD. Such changes may require a permit modification. [OAC 252:100-8-7.2 (b)]

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(18) 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 emergency and/or 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. [The degree of promptness in reporting shall be proportional to the degree of danger.]

[OAC 252:100-8-6 (a)(3)(C)(iii)(II)]

B. 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. [OAC 252:100-8-2]

C. An emergency shall constitute an affirmative defense to an action brought for noncompliance with such technology-based emission limitation if the conditions of paragraph D below are met. [OAC 252:100-8-6 (e)(1)]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that:

(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;
(4) the permittee submitted notice of the emergency to AQD within 24 hours of the time when emission limitations were exceeded due to the emergency. 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; and
(5) the permittee submitted a follow up written report within 10 working days of first becoming aware of the exceedance.

[OAC 252:100-8-6 (e)(2), (a)(3)(C)(iii)(I) and (IV)]

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)]

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, 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. [OAC 252:100-8-2]

(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.

(3) 0.6 tons per year for any one category A substance, 1.2 tons per year for any one category B substance or 6 tons per year for any one category C substance as defined in 252:100-41-40.

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]

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 7 days, or 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 subsection. [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) No person shall cause or permit the discharge of emissions such that National Ambient Air Quality Standards (NAAQS) are exceeded on land outside the permitted facility. [OAC 252:100-3]
(2) 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]
(3) 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]

(4) For all emissions units not subject to an opacity limit promulgated under 40 CFR, Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for 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. [OAC 252:100-25]

(5) 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]

(6) 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]

(7) Volatile Organic Compound (VOC) storage tanks built after December 24, 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)]

(8) 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]

(9) Except as otherwise provided, no person shall cause or permit the emissions of any toxic air contaminant in such concentration as to cause or to contribute to a violation of the MAAC. **(State only)** [OAC 252:100-41]

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.
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.
(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 Sources' 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 Oklahoma Administrative Code 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 Code of Federal Regulations (CFR) § 70.7 (h)(1). This public notice shall include notice to the public that this permit is subject to Environmental Protection Agency (EPA) review, EPA objection, and petition to EPA, as provided by 40 CFR § 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 CFR § 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 CFR § 70.8(a) and (c).
(5) The DEQ complies with 40 CFR § 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 CFR § 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 CFR § 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]

KDHE, BAR
Forbes Field, Building 283
Topeka, KS 66620

SUBJECT: Permit Number: 2003-336-C PSD
Facility: Ponca City Refinery
Project: Ultra-low Sulfur Diesel
Location: Kay County, Oklahoma
Permit Writer: Grover R. Campbell

Dear Sir / Madame:

The subject facility has requested a Tier II PSD construction permit. 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 proposed 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 *http://www.deq.state.ok.us*.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact the permit writer or me at (405) 702-4100.

Sincerely,

Dawson Lasseter, P.E.
Chief Engineer
AIR QUALITY DIVISION

ConocoPhillips
Attn: Dave Gamble
Consultant - Environmental
P.O. Box 1267, 1228EB
Ponca City, OK 74602-1267

Re: Permit Number 2003-336-C (PSD)
ULSD Project

Dear Mr. Gamble:

Enclosed is the modified construction permit for the Ultra Low Sulfur Diesel Project.

Please note that this permit is issued subject to certain standard and specific conditions, which are attached.

Thank you for your cooperation in this matter. If I may be of further service, please contact me at (405) 702-4200.

Sincerely,

Grover R. Campbell, P.E.
Existing Source Permit Section
AIR QUALITY DIVISION

cc: Kay County

PART 70 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

Issuance Date: _____ **Permit Number: 2003-336-C (M-1) PSD**

ConocoPhillips Company, having complied with the requirements of the law, is hereby granted permission to construct the specified equipment for the Ultra-Low Sulfur Diesel and Upgrade Projects at the Ponca City Refinery located in Ponca City, Kay County, OK, subject to the following conditions, attached:

[X] Standard Conditions dated October 15, 2003

[X] Specific Conditions

In the absence of construction commencement, this permit shall expire 18 months from the issuance date, except as authorized under Section VIII of the Standard Conditions.

_____ Director, Air Quality Division