MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY
OPERATING PERMIT TECHNICAL REVIEW DOCUMENT

Permitting and Compliance Division
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P.O. Box 200901
Helena, Montana 59620-0901

ConocoPhillips Company
Billings Refinery
NW¼, Section 2, Township 1 South, Range 26 East, Yellowstone County, MT
P.O. Box 30198
401 South 23rd Street
Billings, Montana 59107-0198

The following table summarizes the air quality programs testing, monitoring, and reporting requirements applicable to this facility.

Facility Compliance Requirements	**Yes**	**No**	**Comments**
Source Tests Required	X		
Ambient Monitoring Required		X	
COMS Required	X		40 CFR Part 51
CEMS Required	X		
Schedule of Compliance Required		X	
Annual Compliance Certification and Semiannual Reporting Required	X		
Monthly Reporting Required		X	
Quarterly Reporting Required	X		In compliance with Stipulation
Applicable Air Quality Programs			
ARM Subchapter 7 Preconstruction Permitting	X		Permit #2619-27
New Source Performance Standards (NSPS)	X		Subpart A, Subpart Db, Subpart Dc, Subpart J, Subpart Ka, Subpart Kb, Subpart UU, Subpart GGG, Subpart QQQ
National Emission Standards for Hazardous Air Pollutants (NESHAPS)	X		Subpart FF, Subpart M
Maximum Achievable Control Technology (MACT)	X		Subpart CC, Subpart UUU, Subpart EEEE, Subpart DDDDD (state-only)
Major New Source Review (NSR), including Prevention of Significant Deterioration (PSD)	X		
Risk Management Plan Required (RMP)	X		
Acid Rain Title IV		X	
State Implementation Plan (SIP)	X		Billings/Laurel SIP
Compliance Assurance Monitoring (CAM) Plan	X		Jupiter SRU/ATS Stack PM/PM_{10}

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SECTION I. GENERAL INFORMATION

A. Purpose

This document establishes the basis for the decisions made regarding the applicable requirements, monitoring plan, and compliance status of emission units affected by the operating permit proposed for this facility. The document is intended for reference during review of the proposed permit by the U.S. Environmental Protection Agency (EPA) and the public. It is also intended to provide background information not included in the operating permit and to document issues that may become important during modifications or renewals of the permit. Conclusions in this document are based on information provided in the original application submitted by Conoco Inc. (Conoco) on June 12, 1996; subsequent settlement stipulation and order of dismissal of Conoco's Title V permit appeal, filed on July 9, 2002; two administrative amendments received December 19, 2002 and October 10, 2003 filed by ConocoPhillips Company (ConocoPhillips); the Title V Renewal application submitted January 9, 2007; an amendment request submitted on July 3, 2008; modification requests received on August 28, 2009 and December 6, 2010; a request for withdrawal of the permit action assigned Operating Permit #OP2619-04 (received on August 29, 2011), and a supplementary request for a modification received on September 19, 2011.

B. Facility Location

The ConocoPhillips Billings Refinery is located at NW¼, Section 2, Township 1 South, Range 26 East, Yellowstone County. This legal description refers to physical address of 401 South 23rd Street, Billings, Montana.

C. Facility Background Information

<u>Montana Air Quality Permit</u>

The refinery processes over 58,000 barrels per day of crude oil and produces a wide range of petroleum products, including propane, gasoline, kerosene/jet fuel, diesel, and petroleum coke. ConocoPhillips has received several air quality permits throughout the past years for various pieces of equipment and operations. All previously permitted equipment, limitations, conditions, and reporting requirements stated in **Permits #1719, #2565, #2669, #2619**, and **#2619A** were included in **Permit #2619-02**.

On October 29, 1982, Conoco received an air quality permit for an emergency flare stack to be equipped and operated with steam injection. This application was given Permit #1719.

On June 2, 1989, Conoco received an air quality permit to convert an existing 5000-barrel cone roof tank (#49) to an internal floating roof with double seals. This conversion was necessary in order to switch service from diesel to aviation gasoline storage. The application was given Permit #2565.

On January 29, 1991, Conoco received an air quality permit to construct and operate two (2) 2000-barrel desalter wastewater break tanks equipped with external floating roofs and double rim seals. The new tanks are to augment the refinery's ability to control fugitive volatile organic compound (VOC) emissions and enhance recovery of oily water from the existing wastewater treatment system. The application was given Permit #2669.

On April 19, 1990, Conoco received an air quality permit to construct new equipment and modify existing equipment at the refinery and construct a sulfur recovery facility, operated by Kerley Enterprises under the control of Conoco, as part of the overall Conoco project. The application was given Permit #2619. Conoco was permitted to construct a new 13,000-barrels-per-stream-day delayed-petroleum coker unit, cryogenic gas plan, gasoline treating unit, and hydrogen system additions. Also, modifications to the existing crude and vacuum distillation units, hydrodesulfurization units, amine treating units and wastewater treatment system were permitted. The sulfur recover facility (Sulfur Recovery Unit/ Ammonium Thiosulfate unit (SRU/ATS)) is to be operated in conjunction with the new installations and modifications at the Conoco Refinery. This SRU/ATS was permitted with the capability of utilizing 109.9 long tons per day of equivalent sulfur obtained from the Conoco Refinery for the manufacture of elemental sulfur and sulfur-containing fertilizer solutions (i.e., ammonium thiosulfate).

On December 4, 1991, Conoco was issued Permit #2619A for the construction of one 1000-barrel hydrocarbon storage tank (T162). This tank will store recovered hydrocarbon product from the contaminated groundwater aquifer beneath the Conoco Refinery. Over the years, surface discharges at the refinery have contaminated the groundwater with oily hydrocarbon products. The purpose of this project is to recover hydrocarbon product (oil) from the groundwater aquifer beneath the refinery. The hydrocarbon product (oil) is pumped out of a cone of depression within the contaminated groundwater aquifer. Groundwater, less the recovered hydrocarbon product, is returned to the aquifer. The application addressed the increase in volatile VOC emissions from the storage of recovered hydrocarbon product.

On March 5, 1993, Conoco was issued Permit #2619-02 for the construction and operation of a 5.0-million standard cubic feet (MMscf)-per-day hydrogen plant and to replace their existing American Petroleum Institute (API) separator system with a corrugated plate interceptor (CPI) separator system. The natural gas feedstock to the new hydrogen plant will produce 99.9% pure hydrogen. This hydrogen and hydrogen from the existing catalytic reformers will be routed to the refinery hydrotreaters to reduce fuel product sulfur content. The hydrogen sulfide produced is, and will continue to be, routed to the SRU/ATS. The two (2) new CPI separator tanks with carbon canister total VOC controls were constructed to comply with 40 CFR 60, Subpart QQQ and 40 CFR 61, Subpart FF regulations. The CPI separators vent to two (2) carbon canisters in series. Each carbon canister shall be designed and operated to reduce VOC emissions by 95%, or greater, with no detectable emissions.

Correspondence received by the Montana Department of Environmental Quality (Department) on December 22, 1992, transferred ownership of the Kerley Enterprises facility to Jupiter Sulphur, Inc. as of December 31, 1992.

On September 14, 1993, Conoco was issued **Permit #2619-03** for the construction and operation of a gas oil hydrotreater and associated hydrogen plant at the Billings refinery. The new hydrotreater desulfurizes a mixture of Fluid Catalytic Cracker (FCC) feed gas oils, which allow the FCC to produce low sulfur gasoline. This low sulfur gasoline is required by January 1, 1995 to satisfy EPA's gasoline sulfur provisions of the Federal 1990 Clean Air Act Amendments. Hydrogen requirements will be met by the installation of a new hydrogen plant. Installing additional elemental liquid sulfur production facilities at the SRU/ATS plant adjacent to the refinery will provide sulfur recovery capacity. The following is a discussion of the project to accomplish this end.

The Gas Oil Hydrodesulfurizer (GOHDS) is designed to meet the primary objective of removing sulfur from the FCC feedstock. A combination of gas oils feed the Gas Oil Hydrotreater. The gas oils are mixed with hydrogen, heated, and passed over a catalyst bed where desulfurization occurs. The gas oil is then fractionated into several products, cooled, and sent to storage. A steam-methane reforming hydrogen plant produces makeup hydrogen for the unit. Any unconsumed hydrogen is amine treated for hydrogen sulfide (H_2S) removal and recycled.

The project did not increase the refinery's capacity. The project did not constitute a major modification for purposes of the Prevention of Significant Deterioration (PSD) program since net emissions did not increase above significant amounts as defined by the ARM 18.8.801(20)(a).

The additional fugitive VOC emissions from this project were calculated by totaling the fugitive sources on the process units. These sources include flanges, valves, relief valves, process drains, compressor seal degassing vents and accumulator vents, and open-ended lines. The fugitive source tabulations were then used with actual refinery emission factors obtained from the Conoco Refinery in Ponca City, Oklahoma. Furthermore, it is intended that each non-control valve in VOC service will be repacked with graphite packing to Conoco standards before installation. All control valves for the GOHDS project will be Enviro-Seal valves or equivalent. The Enviro-Seal valves have a performance specification that exceeds the Subpart GGG standards. The VOC emissions will be validated by 40 CFR 60, Subpart GGG emission monitoring.

As a result of the project, the SRU/ATS facility will consist of three primary units. They are the existing ammonium thiosulfide ATS Plant, the existing Ammonium Sulfide Unit and the addition of the Claus Sulfur and Tail Gas Treating Units (TGTU). The addition of the new units did increase the total sulfur recovery capacity of the facility from 110 to 170 long tons per day (LT/D) of sulfur.

The existing ATS plant consisted of a thermal Claus reaction type boiler. The exit gas from the Claus boiler is incinerated in the ATS Unit. The sulfur dioxide from the incinerator is absorbed and converted to ammonium bisulfite (ABS). The ABS is then used to absorb and react with hydrogen sulfide to produce the ATS product. Up to 110 LT/D of sulfur can be processed by the ATS plant to produce sulfur and ATS.

The ammonium sulfide unit consists of an absorption column, which absorbs the sulfur as hydrogen sulfide in the acid gas feed and reacts with ammonia and water. When the new Claus sulfur unit is added, the SRU/ATS facility will be modified to incinerate any off-gas from this unit in the TGTU and ATS plant. This will eliminate off-gas flow to and emissions from the flare. Up to 110 LT/D of sulfur can be processed by the ammonium sulfide unit to produce ammonium sulfide solution.

The new Claus sulfur unit consists of a thermal Claus reaction furnace followed by a waste heat boiler and three catalytic Claus reaction beds. The Claus tail gas is then incinerated before entering the TGTU. In this new unit, the sulfur dioxide from the incinerator is absorbed and converted to ABS. This ABS is then transferred to the ATS unit for conversion. Up to 110 LT/D of sulfur can be processed by the Claus sulfur unit to produce sulfur and ABS. The ABS from the TGTU is dilute, containing a significant amount of water that was generated from the Claus reaction. To prevent making a dilute ATS from this "weak" ABS, a new ATS reactor was added to the ATS unit. This ATS reactor will combine "weak" ABS, additional ABS, and sulfur to make a full strength ATS solution.

An important feature of the Jupiter Sulphur, Inc. facility is its capability to process Conoco's sour gases at all times. A maximum of 170 LT/D of sulfur is planned to be recovered and each of the three units have a capacity of 110 LT/D. If any of the three is out of service, then the other two can easily handle the load. While the process has 100% redundancy, any two of the three units must be running to handle the design load. The process uses high efficiency gas filters, which employ a water-flush coalescer cartridge to reduce particulate, as well as sulfur compounds.

On November 11, 1993, Conoco was issued **Permit #2619-04** to construct and operate a new compressor station and associated equipment at the Billings Refinery. The C-23 compressor station project will involve the recommissioning of an out-of-service compressor and associated equipment components having fugitive VOC emissions. The project will also involve the installation of new equipment components having fugitive VOC emissions. The recommissioned compressor was originally installed in 1948. The compressor will undergo some minor refurbishing, but will not trigger "reconstruction" as defined in 40 CFR 60.15. The purpose of the C-23 compressor station project is to improve the economics of the refinery's wet gas (gas streams containing recoverable liquid products) processing through increased yields and more efficient operation in the refinery's large and small Crude Topping Units (CTUs) and the Alkylation unit. The project also improved safety in the operations of the two CTUs, Alkylation unit, and Gas Recovery Plant (GRP). As a result of this project, the vapor pressure of the alkylate product (produced by the Alkylation unit) will be lower.

On February 2, 1994, Conoco was issued **Permit #2619-05** to construct and operate a new butane defluorinator within the alkylation unit at the refinery. Installation of an alumina (AL_2O_3) bed defluorinator system is to remove residual hydrofluoric acid (HF) and organic fluorides from the butane stream produced by the alkylation unit. This will reduce the fluorine level of the butane from ~ 500 parts per million, weight (ppmw) to ~ 1 ppmw, which will allow the butane to be recycled back to the refinery's butamer unit for conversion into isobutane. The alkylation unit butane defluorinator project resulted in: (1) changes in operation of the alkylate stabilization train of the alkylation unit to yield defluorinated butane instead of fluorinated and lower vapor pressure alkylate products; (2) changes in operations of the refinery's gasoline blending to restructure butane blending and lower the vapor pressure of the gasoline pool; (3) minimize butane sales; (4) minimize butane burning as refinery fuel gas; and (5) economize gasoline blending of butane.

On March 28, 1994, Conoco was issued **Permit #2619-06** to construct and operate equipment to support a new polymer modified asphalt (PMA) unit at the refinery. The PMA project allowed Conoco to produce asphalt that meets the new federal specifications and become a supplier of PMA for the region. A 9.5-million British thermal unit per hour (MMBtu/hr) natural gas-fired process heater, to heat an oil heat transfer fluid, was installed to bring the asphalt base to 400 ºF. This allows a polymer material to be mixed with it to produce PMA. A new hot oil transfer pump was installed to circulate hot oil through the system. A heat exchanger (X-364) from the shutdown PDA unit was moved and installed to aid in the heating of the asphalt base. Two existing 5000-bbl asphalt storage tanks were converted to PMA mixing and curing tanks. This required the installation of additional agitators, a polymer pellet loading (blower) system and conversion of the tank steamcoil heating system to hot oil heated by the new process heater. New asphalt transfer line, a new asphalt transfer pump and a new 5000 bbl PMA storage tank (replacing the demolished T-50) was installed to keep the PMA separated from other asphalt products.

On July 28, 1995, Conoco was issued **Permit #2619-07** for the construction and operation of new equipment within the refinery's alkylation (alky) and gas recovery plant/No.1 Amine units. This project was referred to as the Alkylation Unit Depropanizer Project. The existing Alkylation unit was replaced with a new tower. The new depropanizer is located where the No.1 Bio-pond was located. Piping and valves were added and the new depropanizer was located next to existing equipment. The old depropanizer was retained in place and may be used in the future in a non-Hydrogen Fluoride (HF) service. The decommissioned propane deasphalting (PDA) unit evaporator tower (W-3) was converted to a water wash tower to remove entrained amine from the Alky PB (Propene/Butene) olefins upstream of the PB merox prewash. New piping, valves, and instrumentation were added around W-3. The change in air emissions associated with this project were increases in fugitive VOC emissions, as well as additional emissions of fluorides due to the installation of the new depropanizer piping and valves. The changes associated with this project did not trigger PSD review because the sum of the emission rate increases is below PSD significant emission rates for applicable pollutants. The drains installed or reused tie into parts of the refinery's wastewater sewer system that are already subject to NSPS Subpart QQQ (Wastewater Treatment System VOC Emissions in Petroleum Refineries) and NESHAP Subpart FF (Benzene Waste Operations). These drains will be equipped with tight fitting caps and have hard pipe connections to meet the required control specifications.

On July 24, 1996, Conoco was issued **Permit #2619-08** to change the daily sulfur dioxide (SO_2) emission limit of the 19 existing process heaters, as well as combining the 19 heaters, the Coker heater (H-3901), and the GOHDS heaters (H-8401 and H8402) into one SO_2 point source within the Refinery. The project was referred to as the Existing Heater Optimization Project.

The 19 process heaters being discussed in this project are the process heaters (excluding H-3 and H-7) that were in operation prior to the construction of the Delayed Coker/Sulfur Reduction Project, which became fully operational in May of 1992. The 19 heaters are: H-1, H-2, H-4, H-5, H-10, H-11, H-12, H-13, H-14, H-15, H-16, H-17, H-18, H-19, H-20, H-21, H-22, H-23, and H-24. These 19 heaters are pooled together and regulated as one source, referred to as the "19 Heaters" source. Also included in this discussion are the Coker heater (H-3901) and the GOHDS heaters (H-8401 and H-8402).

The 19 heaters had a "bubbled" SO_2 emissions limit of 30.0 tons per year (tpy) (164 pounds per day (lb/day)) and a limitation of fuel gas H_2S content of 160 parts per million, volume (ppmv, 0.1 grain/dry standard cubic foot (dscf)). With both these limitations intact, all these heaters could not simultaneously operate at their maximum-design firing rates. This could cause un-optimized operation of the refinery during unfavorable climatical conditions or during peak heater demand periods. To allow all 19 of the heaters to simultaneously operate at their maximum firing rates, the allowable short-term SO_2 emissions limit for the "bubbled" 19 heaters needed to be increased. The 19 refinery fuel gas heaters/furnaces lbs/day SO_2 emission limitations were based on NSPS fuel gas (160 ppm H_2S), maximum heat input (MMBtu/hr) from the emission inventory database (AFS), and higher fuel heat value (1015 Btu/scf) from the 1990 Base Year Carbon Monoxide Emission Inventory. By using these parameters, the daily "bubble" SO_2 permit limit could be raised to 386 lb/day, as was indicated in the Preliminary Determination (PD).

Conoco requested that the daily limit be increased to 612 lb/day, which is equivalent to the rate used in the Billings SO_2 SIP modeling (111.7 tpy). The annual "bubble" SO_2 limit of 30 tpy was maintained. The Department received comments from Conoco in which Conoco contended that the maximum heat input (MMBtu/hr) from AFS did not accurately reflect the real maximum firing rates of the heaters. After further review of the files, the Department established the total maximum firing rate for the 19 refinery fuel gas heaters/furnaces to be 785.5 MMBtu/hr. ConocoPhillips identified the total maximum firing rate during the permit review of the Coker permit (Permit #2619). The maximum heat input of 785.5 MMBtu/hr and the fuel heat value of 958 Btu/scf were used to calculate the new daily "bubble" SO_2 permit limit of 529.17 lb/day.

The change in air emissions of other criteria pollutants (carbon monoxide (CO), oxides of nitrogen (NO_x), particulate matter (PM), and VOC) associated with this project was zero, since the potential to emit for these pollutants did not change. With the 164-lb/day SO_2 limit, simultaneous maximum firing of these heaters could be accomplished if the fuel gas H_2S content stayed below 49.75 ppmv. Conoco's amine systems produced fuel gas averaging (on an annual basis) about 25-ppmv H_2S content or less (see the 1993 and 1994 refinery EIS's). Since the emissions of CO, NO_x, and VOC produced are not a function of H_2S content and Conoco's amine system could generate appropriate fuel gas to stay at or below the 164-lb/day SO_2 limit, the maximum potentials of these pollutants are obtainable and not affected by this project. The PM limits for these heaters are 80 times higher than the amount generated by fuel gas combustion devices (see ARM 17.8.340); therefore, the PM emissions potential is not affected as well.

Even though Conoco's past annual average fuel gas H_2S content had been below 37.8 ppmv, there would still be potential to run into operational limitations in peak fuel gas demand periods. The amine systems may not have been able to keep the fuel gas H_2S under 49.75 ppmv, rendering the refinery to operate at un-optimal rates. This was the reason for the request to raise the daily SO_2 emissions limit for the 19-heater source.

Since the proposed change to the heaters' SO_2 emissions limit does not reflect an annual increase in potential to emit, the project did not trigger PSD permitting review (threshold for SO_2 is 40 tpy).

In light of the SO_2 problem in the Billings-Laurel air shed, any change resulting in an increase of SO_2 emissions must have its impact determined to see if any National Ambient Air Quality Standards (NAAQS) will be violated as a result of the project. SO_2 modeling was completed by the Department to develop a revised SO_2 State Implementation Plan (SIP) for the Billings-Laurel area. The "19-heater source" was modeled using an SO_2 emission rate equivalent to 111.7 tpy to determine its existing SO_2 impact on the Billings-Laurel air shed. The results of this modeling showed there were no exceedances of the SO_2 NAAQS or the Montana standards resulting from it operation. Therefore, an increase in the permit limit from 164 lb/day to 612 lb/day of SO_2 will not result in any violations of SO_2 NAAQS or the Montana standards. However, the daily emission limits set based on the NSPS limit of 0.1 grain/dscf

(160 ppmv H_2S) are more restrictive that the SIP limit. The daily emission limits set based on NSPS is 529.17 lb/day for the existing 19 heaters/furnaces.

In addition to changing the daily SO_2 permit limit for the "19-heater source", Conoco requested that the "19 heater source", the Coker Heater (H-3901), and the GOHDS heaters (H-8401 and H-8402) be combined into one permitted source called the "Fuel Gas Heater" source. Using the existing daily SO_2 permit limits for the Coker heater and GOHDS heaters, an overall SO_2 emissions limit "bubble" of 614 lb/day would apply to the "22-Fuel Gas Heaters" source. The annual limit for the "22-Fuel Gas Heaters" source has not changed and is 45.50 tpy (30.00 + 9.60 + 2.90 + 3.00).

On April 19, 1997, Conoco was issued **Permit #2619-09** to "bubble" or combine the allowable hourly and annual NO_x emission limits for the Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heaters. The NO_x emission limits for these heaters were established on a pounds-per-million-Btu basis and will be maintained. By "bubbling" or combining the allowable hourly and annual NO_x emission limits for the Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heaters would allow Conoco more operational flexibility with regard to heater firing rates and heater optimization. The Coker heater will still have an hourly NO_x emission limit to prevent any significant impacts. The permitting action did not allow an increase in the annual NO_x emissions.

On July 30, 1997, **Permit #2619-10** was issued to Conoco in order to comply with 40 CFR 63, Subpart R- National Emission Standards for Gasoline Distribution Facilities. Conoco proposed to install a gasoline vapor collection system and enclosed flare for the reduction of Hazardous Air Pollutants (HAPs) resulting from the loading of gasoline. The vapor combustion unit (VCU) was added to the bulk gasoline and distillate loading rack. The gasoline vapors are collected from the trucks during loading, then routed to an enclosed flare where combustion occurs. This project resulted in an overall reduction in the amount of actual emissions of VOCs (94.8 tpy). The reduction in potential emissions of VOCs is 899.5 tpy, while CO increases to 19.7 tpy and NO_x increases to 7.9 tpy emissions.

Conoco also requested an administrative change be made to Section II.F.5, that would bring the permit requirements in alignment with the monitoring requirements specified by 40 CFR 60, Subpart QQQ and 40 CFR 61, Subpart FF.

Because Conoco's bulk gasoline and distillate loading rack VCU is defined as an incinerator under MCA 75-2-215, a determination that the emissions from the VCU will constitute a negligible risk to public health was required prior to the issuance of the permit. Conoco and the Department identified the following hazardous air pollutants from the flare, which were used in the health risk assessment. These constituents are typical components of gasoline.

1. Benzene
2. Ethyl Benzene
3. Hexane
4. Methyl Tert Butyl Ether
5. Toluene
6. Xylenes

The reference concentrations for Ethyl Benzene, Hexane, and Methyl Tert Butyl Ether were obtained from EPA's IRIS database. The risk information for the remaining hazardous air pollutants is contained in the January 1992 CAPCOA Risk Assessment Guidelines. The model performed by Conoco for the hazardous air pollutants, identified above, monitored compliance with the negligible risk requirement.

On December 10, 1997, Conoco requested a modification to allow the continuous incineration of a PB Merox Unit off gas stream in the firebox of Heater #16. **Permit #2619-11** requires the production of sulfur dioxide from the sulfur-containing compounds in the PB Merox Unit off gas stream to be calculated and counted against the current sulfur dioxide limitations applicable to the (22) Refinery Fuel Gas Heaters/Furnaces group. During a review of process piping and instrumentation diagrams, Conoco identified a PB Merox Unit off-gas stream that is currently incinerated in the firebox of Heater #16. A subsequent analysis of this off-gas stream revealed the presence of sulfur-containing compounds in low concentrations. The bulk of this low-pressure off-gas stream is nitrogen with some oxygen, hydrocarbons, and sulfur-containing compounds (disulfides, mercaptans). Sulfur dioxide produced from the continuous incineration of this stream has been calculated at approximately 1 ton per year. This off-gas stream is piped from the top of the disulfide separator through a small knock out drum and directly into the firebox of Heater #16.

Conoco proposes to sample the PB Merox Unit disulfide separator gas stream on a monthly basis to determine the total sulfur (ppmw) present. This analysis, combined with the off-gas stream flow rate, will be used to calculate the production of sulfur dioxide. After a year of sampling time, and with the approval of the Department, Conoco proposes to reduce the sampling frequency of the PB Merox disulfide separator off-gas stream to once per quarter if the variability in the sulfur content is small (±250 ppmw).

In addition, to be consistent with the wording as specified by 40 CFR 63, Subpart R, the Department replaced all references to "tank trucks" with "cargo tank" and all references to "truck-loading rack" with "loading rack". Also, the first sentence in Section II.F.5 of the preconstruction permit was deleted from the permit. Conoco had requested an administrative change be made to Section II.F.5, during the permitting action of #2619-10, which would bring the permit requirements in alignment with the monitoring requirements specified by 40 CFR 60, Subpart QQQ, and 40 CFR 61, Subpart FF. The Department had approved the request and the correction was made; however, the first sentence was inadvertently left in the permit. Permit #2619-11 replaced Permit #2619-10.

On June 6, 2000, the Department issued **Permit #2619-12** for replacement of the B-101 thermal reactor at the Jupiter Sulphur facility. The existing B-101 thermal reactor had come to the end of its useful life and had to be replaced. The replacement B-101 thermal reactor was physically located approximately 50 feet to the north of the existing thermal reactor, due to the excessive complications that would be encountered to dismantle the old equipment and construct the new equipment in the same space. Once the piping was rerouted to the new equipment the old equipment was incapable of use and will be demolished. Given this construction scenario, the Department determined that a permit condition limiting the operation to only one thermal reactor at a time was necessary. There was no increase in emissions due to this action. Permit #2619-12 replaced Permit #2619-11.

Conoco submitted comments on the Preliminary Determination (PD) of Permit #2619-12. The following is the result of these comments:

- In previously issued permits, Section II.A.4 listed storage tanks #4510 and #4511 as having external floating roofs with primary seal, which were liquid mounted stainless steel shoes and secondary seal equipped with a Teflon curtain or equivalent. Conoco stated that these two tanks were actually equipped with internal floating roofs with double-rim seals or a liquid-mounted seal system for VOC loss control.

- Section II.A.7.g.ii always listed the CPI separators as primary separators, when in fact they are secondary.

The Department accepted the comments and made the changes, accordingly, in the Department decision version of the permit.

On March 1, 2001, the Department issued **Permit #2619-13** for the installation and operation of 19 diesel-powered, temporary generators. These generators are necessary because of the high cost of electricity and supplement 18 megawatts (MW) of the refinery’s electrical load, and 1 MW of Jupiter’s electrical load.

The generators are located south of the coke loading facility along with two new aboveground 20,000-gallon diesel storage tanks. The operation of the generators will not occur beyond 2 years and is not expected to last for an extended period of time, but rather only for the length of time necessary for Conoco to acquire a permanent, more economical supply of power.

Because these generators are only to be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of these generators is minor. In addition, the installation of these generators qualified as a "temporary source" under the PSD permitting program because the permit limited the operation of these generators to a time period of less than 2 years. Therefore, Conoco was not required to comply with ARM 17.8.804, 17.8 820, 17.8.822, and 17.8.824. Even though the portable generators were considered temporary, the Department required compliance with Best Available Control Technology (BACT) and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 was ensured. In addition, Conoco is responsible for complying with all applicable ambient air quality standards. Permit #2619-13 replaced Permit #2619-12.

On April 13, 2001, the Department issued **Permit #2619-14** for the 1982 Saturate Gas Plant Project, submitted by Conoco as a retroactive permit application. During an independent compliance awareness review that was performed in 2000, Conoco discovered that the Saturate Gas Plant should have gone through the permitting process prior to it being constructed. At the time of construction, the project likely would have required a PSD permit. However, the current potential to emit for the project facility is well below the PSD VOC significance threshold. In addition, the Saturate Gas Plant currently participates in a federally-required leak detection and repair (LDAR) program, which would meet any BACT requirements, if PSD applied. The Department agreed that a permitting action in the form of a preconstruction permit application for the Saturate Gas Plant Project was necessary and sufficient to address the discrepancy. Permit #2619-14 replaced Permit #2619-13.

On June 29, 2002, the Department issued **Permit #2619-15** to clarify language regarding the Appendix F Quality Assurance requirements for the fuel gas H_2S measurement system and to include certain limits and standards associated with the Consent Decree lodged on December 20, 2001, respectively. In addition, the Department modified the permit to eliminate references to the now repealed odor rule (ARM 17.8.315), to correct the reference on conditions improperly referencing the incinerator rule (ARM 17.8.316), and to eliminate the limits on the main boiler that were less stringent than the current limit established by the Consent Decree. Permit #2619-15 replaced Permit #2619-14.

The Department received a request from Conoco on August 27, 2002, for the alteration of air quality Permit #2619-15 to incorporate the Low Sulfur Gasoline (LSG) Project into the refinery's equipment and operations. The LSG Project was being proposed to assist in complying with EPA's Tier 2 regulations. The project included the installation of a new storage vessel and minor modifications to the No.2 hydrodesulfurization (HDS) unit, GOHDS unit, and hydrogen (H_2) unit in order to accommodate hydrotreating additional gasoline and gas oil streams that were currently not hydrotreated prior to being blended or processed in the FCC unit. The new storage vessel was designed to store offspec gasoline during occasions when the GOHDS unit was offline.

In addition, on August 28, 2002, Conoco requested to eliminate the footnote contained in Section II.B.1.b of Permit #2619-15 stating, "Emissions [of the SRU Flare] occur only during times that the ATS unit is not operating." Further, Conoco requested to change the SO_2 emission limitations of 25 pounds per hour (lb/hr) for each of the SRU Flare and SRU/ATS Main Stack to a 25-lb/hr limit on the combination of the SRU Flare and SRU/ATS Main Stack. Following discussion between Conoco and the Department regarding comments received within the Department and from EPA, Conoco requested an extension to delay issuance of the Department Decision to December 9, 2002. Following additional discussion, Conoco and the Department agreed to leave the footnote in the permit for the issuance of **Permit #2619-16** and to revisit the issue at another time. Permit #2619-16 replaced Permit #2619-15.

A letter from ConocoPhillips dated December 9, 2002, and received by the Department on December 10, 2002, notified the Department that Conoco had changed its name to ConocoPhillips. In a letter dated February 3, 2003, ConocoPhillips also requested the removal of the conditions regarding the temporary power generators because the permit terms for the temporary generators were "not to exceed 2 years" and the generators had been removed from the facility. The permit action changed the name on this permit from Conoco to ConocoPhillips and removed permit terms regarding temporary generators. **Permit #2619-17** was also updated to reflect current permit language and rule references used by the Department. Permit #2619-17 replaced Permit #2619-16.

On December 11, 2003, the Department received a Montana Air Quality Permit (MAQP) Application from ConocoPhillips to modify Permit #2619-17 to replace the existing 143.8- MMBtu/hr boilers, B-5 and B-6, with new 183-MMBtu/hr boilers equipped with low NO_X burners (LNB) and flue gas recirculation (FGR) commonly referred to as ultra-low NO_X burners (ULNB), new B-5 and new B-6 (previously referred to as B-7 and B-8), to meet the NO_X emission reduction requirements stipulated in the EPA Consent Decree. On December 23, 2003, the Department deemed the application complete. This permitting action contained NO_X emissions that exceeded PSD significance levels. The replacement of the boilers resulted in an actual NO_X reduction of approximately 89 tons per year. However, the EPA Consent Decree stipulated that reductions were not creditable for PSD purposes. Permit #2619 was also updated to reflect current permit language and rule references used by the Department. **Permit #2619-18** replaced Permit #2619-17.

On February 3, 2004, the Department received a MAQP Application from ConocoPhillips to modify Permit #2619-18 to add a new HDS Unit (No.5), a new sour water stripper (No.3 SWS), and a new H_2 Unit. On March 1, 2004, the Department deemed the application complete upon submittal of additional information. The addition of these new units added three new heaters, 41, 42, and 43, each equipped with low LNB FGR commonly referred to as ULNB. Additionally, ConocoPhillips proposed to retrofit existing external floating roof tank T-110 with a cover to allow nitrogen blanketing of the tank, to install a new storage vessel (No.5 HDS Feed storage tank) under emission point 24 above, to store feed and off-specification material for the No.5 HDS Unit, and to provide the No.1 H_2 Unit with the flexibility to burn refinery fuel gas (RFG). The new equipment was added to meet the new EPA-required highway Ultra Low Sulfur Diesel (ULSD) fuel sulfur standard of 100% of highway diesel that meets the 15 parts per million (ppm) highway diesel fuel maximum sulfur specification by June 1, 2006. By meeting the June 1, 2006, deadline, ConocoPhillips may claim a 2-year extension for the phase-in of the requirements of the Tier Two Gasoline/Sulfur Rulemaking. This permitting action resulted in NO_X and VOC emissions that exceed PSD significance levels. Other changes were also contained in this permit. Previously in permit condition II.A.1 it was stated that the emergency flare tip must be based at 148-feet elevation. After a physical survey of the emergency flare it was determined that the actual height of the flare tip is 141.5-feet elevation. After verifying that the impacts of the height discrepancy were negligible, the Department changed permit condition II.A.1 from 148-feet of elevation to 142-feet plus or minus 2 feet of elevation and changed the reference from ARM 17.8.752 to ARM 17.8.749. **Permit #2619-19** was updated to reflect current permit language and rule references used by the Department. Permit #2619-19 replaced Permit #2619-18.

On June 15, 2004, the Department received an Administrative Amendment request from ConocoPhillips to modify Permit #2619-19 to correct the averaging time for equipment subject to the 0.073 gr/dscf H_2S content of fuel gas burned limit. The averaging time was corrected from a rolling 3-hour time period to a rolling 12-month time period. The heaters subject to the 0.073 gr/dscf limit per rolling 12-month time period are subject to the Standards of Performance for NSPS, Subpart J limit of 0.10 gr/dscf per rolling 3-hour time period. **Permit #2619-20** replaced Permit #2619-19.

On March 15, 2005, the Department received a complete MAQP Application from ConocoPhillips to modify Permit #2619-20 to update the HDS Unit (No.5), sour water stripper (No.3 SWS), and H_2 Unit added in ULSD Permit Modification #2619-19. Due to the final project design and vendor specifications, and further review of the EPA compiled emission factor data, the facility's emission generating activities, and Permit #2619-19, ConocoPhillips proposed the following changes:

1. Deaerator Vent (44) at the No.2 H_2 Unit is to be deleted;

2. No.2 H_2 Unit PSA Off-gas Vent (45) is to be added;

3. CO emission factors for the three new heaters to be changed from AP-42 Section 1.4 (October 1996) to vendor guaranteed emission factors;

4. Particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) exhaust emission factors for the combustion of PSA vent gas in the No.1 H_2 Heater and the No.2 H_2 Reformer Heater to be changed from AFSCF, EPA 450/4-90-003 p.23 to AP-42, Section 1.4 (July 1998);

5. The dimensions, secondary rim seal, and specific deck fittings data for the No.5 HDS Feed Tank to be updated. The tank is proposed to store material with a maximum true vapor pressure of 11.1 pounds per square inch at atmosphere (psia).

6. Specific deck fittings for existing Tank-110 to be revised. The tank is proposed to store material with a maximum true vapor pressure of 11.1 psia.

7. The existing No.1 H_2 Unit PSA Off-gas Vent (46) to be added to the permit. This unit is not affected by the ULSD project, but is included with this submittal as a reconciliation issue.

8. The NO_X emissions limitations cited for each of the three new ULSD Project heaters are requested to be clarified as "per rolling 12-month time period."

9. The CO emissions limitations cited for each of the three new ULSD Project heaters be replaced and cited with the appropriate updated values and associated averaging periods.

10. The nomenclature for Boilers B-7 and B-8 be changed to new B-5 and new B-6 respectively.

11. In accordance with Paragraph 54 of the Consent Decree the FCC UNIT became subject to the SO_2 portions of 40 CFR 60, Subpart J on February 1, 2005.

12. 40 CFR 63, Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters) has been finalized. The regulatory applicability analysis has been updated for the three new heaters.

Permit #2619-21 replaced Permit #2619-20.

On January 15, 2007, the Department received a complete application which included the request to incorporate the following permit conditions, which were requested in separate letters:

- Refinery Main Plant Relief Flare – to clarify that the flare is subject to 40 CFR 60, Subparts A and J (as requested September 28, 2004);

- FCC – to clarify that the FCC is subject to CO and SO_2 portions of Subpart J (requested September 26, 2003, and February 8, 2005, respectively, and partly addressed in Permit #2619-21);

- FCC - to clarify that the FCC was subject to an SO_2 emission limit of 25 parts per million, on a volume, dry basis (ppmvd), corrected to 0% oxygen (O_2), on a rolling 365-day basis, and subject to an SO_2 emission limit of 50 ppmvd, corrected to 0% O_2, on a rolling 7-day basis, and clarify the 7-

day SO_2 50 ppmvd emission limit established for the FCC Unit shall not apply during periods of hydrotreater outages (requested February 1, 2006); and

- Temporary Boiler Installation – to allow the installation and operation, for up to 8 weeks per year, of a temporary natural gas-fired boiler not to exceed 51 MMBtu/hr, as requested January 4, 2007.

The permit was also updated to reflect the current style that the Department issues permits. **Permit #2619-22** replaced Permit #2619-21.

The Department has received two requests from ConocoPhillips for modifications to the permit in conformance with requirements contained in their consent decree (Civil Action #H-01-4430):

- 5/31/07 – request to clarify that the Jupiter Sulfur Plant Flare (Jupiter Flare) is subject to 40 CFR 60, Subparts A and J; and

- 8/29/07 – request to clarify that the Fluid Catalytic Cracking (FCC) Unit is subject to a Particulate Matter (PM) emission limit of 1 lb per 1000 lb of coke burned, and that it is an affected facility subject to 40 CFR 60, Subparts A and J, including the 30% opacity limitation. The requirement to maintain less than 20% opacity was then removed, since the FCC Unit became subject to the 30% Subpart J opacity limit which supersedes the ARM 17.8.304 opacity limit.

The Department amended the permit, as requested. In addition, the references to 40 CFR 63, Subpart DDDDD were changed to reflect that this regulation has become "state-only" since, although the federal rule was vacated on July 30, 2007, this MACT was incorporated by reference in ARM 17.8.342. Lastly, reference to Tank T-4524 was corrected to T-4523 (wastewater surge tank) and regulatory applicability changed from 40 CFR 60, Subpart Kb to Subpart QQQ, and the LSG tank identification was corrected to T-2909. **MAQP #2619-23** replaces MAQP #2619-22.

On August 21, 2008, the Department received a complete NSR-PSD permit application from ConocoPhillips. ConocoPhillips proposed to replace the existing Small and Large Crude Units and the existing Vacuum Unit with a new, more efficient Crude and Vacuum Unit. This projectwas referred to as the New Crude and Vacuum Unit (NCVU) project. The NCVU project enabled ConocoPhillips' Billings refinery to process both conventional crude oils and SynBit/oil sands crude oils and increase crude distillation capacity about 25%. The NCVU project required modifications and optimization of the following existing process units: No. 2 HDS Unit, Saturate Gas Plant, No. 2 and No. 3 Amine Units, No. 5 HDS Unit, Coker Unit, No. 1 and 2 H_2 Plants, Hydrogen Purification Unit (HPU), Raw Water Demineralizer System, Jupiter SRU/ATS Plant, and the FCCU. The primary objectives of the NCVU Project were to improve crude fractionation and energy efficiency of the refinery, and to increase crude processing capacity and crude feed flexibility to reduce feed costs. As a result of the NCVU Project, the Jupiter Plant feed rate capacity needed to be increased to approximately 235 LTD of sulfur. With the submittal of this complete application, the minor source baseline dates for SO_2, PM, and PM_{10} was triggered in the Billings area as of August 21, 2008. The minor source baseline date for NO_x was already established by Yellowstone Energy Limited Partnership (formerly Billings Generation Inc.) on November 8, 1991.

In addition, the Department clarified the permit language for the bulk loading rack VCU regarding the products that may be loaded in the event the VCU is inoperable. **MAQP #2619-24** replaced MAQP #2619-23.

On June 12, 2009, the Department received a request from ConocoPhillips to administratively amend MAQP #2619-24 to include certain limits and standards. This amendment was in response to requirements contained in the Consent Decree (CD) that ConocoPhillips has entered into with EPA along with the Department. The CD was set forth on December 20, 2001.

As a result of the requirements set forth within the CD, ConocoPhillips had requested the following limits and standards (agreed to by EPA) to be included in the MAQP:

The NO_x emissions from the FCCU shall have a limit of 49.2 parts per million, volumetric dry (ppmvd), corrected to 0% O_2, on a rolling 365-day average and 69.5 ppmvd, corrected to 0% O_2, on a rolling 7-day average. Per Paragraph 27 of the above-referenced CD, the 7-day NO_x emission limit established for the FCC shall not apply during periods of hydrotreater outages at the refinery, provided that ConocoPhillips is maintaining and operating its FCC (including associated air pollution control equipment) in a manner consistent with good air pollution control practices for minimizing emissions in accordance with the EPA-approved good air pollution control practices plan.

As a result of this request, **MAQP #2619-25** replaced MAQP #2619-24.

On December 6, 2010, the Department received a request from ConocoPhillips to administratively amend MAQP #2619-25 to include certain limits, standards, and obligations in response to agency requests and the requirements of Paragraph 210(a) contained the ConocoPhillips CD. ConocoPhillips also requested to include conditions pertaining to facility-related Supplemental Environmental Projects (SEP), although not specifically required by the ConocoPhillips CD. ConocoPhillips later rescinded the request to include these SEP conditions within this permit action. ConocoPhillips additionally requested removal of references to Tank #162 (Ground Water Interceptor System (GWIS) Recovered Oil Tank) as this tank has been taken out of service. With knowledge of forthcoming additional information and administrative amendment requests, in concurrence with ConocoPhillips, the Department withheld preparation and issuance of a revised MAQP; however, this action was assigned MAQP #2619-26.

On July 28, 2011, the Department received a request from ConocoPhillips to administratively amend MAQP #2619-25 to include the following language (underlined):

> NO_x emissions shall not exceed 49.2 ppmvd corrected to 0% O_2, on a rolling 365-day average and 69.5 ppmvd, corrected to 0% O_2, on a rolling 7-day average. The 7-day NO_x emission limit shall not apply during periods of hydrotreater outages, provided that ConocoPhillips is maintaining and operating the FCCU (including associated air pollution control equipment) consistent with good air pollutions control practices for minimizing emissions in accordance with the EPA-approved good air pollution control practices plan. <u>For days in which the FCCU is not operating, no NOx value shall be used in the average, and those periods shall be skipped in determining the 7-day and 365-day averages</u> (ConocoPhillips Consent Decree, Paragraph 27, as amended).

ConocoPhillips requested this addition in language as a result of an April 29, 2011 letter from EPA, which contained the formal approval of the FCC NOx emission limits required by the CD. The letter included EPA's expectations as to how these NOx emission concentration averages are to be calculated.

This amendment to MAQP #2619-25 included the requested changes from the December 6, 2010 and July 28, 2011 administrative amendment requests.

As a result of both of these requests, **MAQP #2619-27** replaced MAQP #2619-25.

<u>Title V Operating Permit</u>

Operating Permit #OP2619-00 was issued final and effective on July 9, 2002.

A letter from ConocoPhillips dated December 9, 2002, and received by the Department on December 10, 2002, notified the Department that Conoco had changed its name to ConocoPhillips. On October 10, 2003, the Department received a request from ConocoPhillips for an administrative amendment of OP2619-00 to update Section V.B.3 of the General Conditions incorporating changes to federal Title V rules 40 CFR 70.6(c)(5)(iii)(B) and 70.6(c)(5)(iii)(C) (to be incorporated into Montana's Title V rules at

ARM 17.8.1213) regarding Title V annual compliance certifications. The permit action changed the name on this permit from Conoco to ConocoPhillips and updated Section V.B.3 of the General Conditions. **Operating Permit #OP2619-01** replaced Operating Permit #OP2619-00.

On January 9, 2007, the Department received an application for renewal of Permit #OP2619-01. The submittal included the request to remove the ConocoPhillips Pipe Line Company operations from this operating permit and establish a new operating permit for these transportation operations (Permit #OP4056-00). In addition, the renewal application requested the inclusion of numerous modifications made since the issuance of the original Title V permit application. **Operating Permit #OP2619-02** replaced Operating Permit #OP2619-01.

On July 3, 2008, ConocoPhillips requested an amendment to **Operating Permit #OP2619-02** on the basis of the inclusion of the entire Consent Decree (H-01-4430 as lodged on April 30, 2002 and as subsequently amended) in that permit. It is ConocoPhillips' position that ARM 17.8.1211(2) only allows consent decree requirements to be included that are as a result of non-compliance with a specific rule or regulatory requirement. The Department included the Consent Decree because it considered the Consent Decree requirements as relevant terms and conditions required to be included in the Title V Operating Permit. The following language (and changes to the permit as described below), as requested by ConocoPhillips, satisfy both ConocoPhillips and the Department with respect to inclusion of Consent Decree requirement into the Title V Operating Permit:

> *"ConocoPhillips Company (a successor to Conoco Inc.) has entered into a Consent Decree (Civil Action H-01-4430 as lodged on April 30, 2002 and as subsequently amended). Certain consent decree emission limits, standards and schedules have been incorporated as terms and conditions of the permit, into the appropriate sections of this permit. Other consent decree requirements are considered program enhancements and are not included as terms or conditions of the permit. These requirements found in Appendix H of the permit, may be enforced by the State of Montana and the United States Environmental Protection Agency pursuant to the provisions of the consent decree."*

In addition to the amendment regarding the Consent Decree, the permit also reflected a requested change in Responsible Official (also submitted on July 3, 2008). **Operating Permit #OP2619-03** replaced Operating Permit #OP2619-02.

D. Current Permit Action

On August 21, 2008, the Department received a complete NSR-PSD permit application from ConocoPhillips. ConocoPhillips proposed to replace the existing Small and Large Crude Units and the existing Vacuum Unit with a new, more efficient Crude and Vacuum Unit. This project is referred to as the New Crude and Vacuum Unit (NCVU) project and was ultimately assigned Operating Permit #OP2619-04. Due to difficulties associated with preparation of an Operating Permit (including conditions, limitations, and associated compliance demonstrations) for an unconstructed facility, this permit was put on hold until construction.

As a result of the requirements set forth within the CD, on August 28, 2009, the Department received from ConocoPhillips a request to include the following limits and standards (agreed to by EPA) to be included in Operating Permit #OP2619-03:

> The NO_x emissions from the FCCU shall have a limit of 49.2 parts per million, volumetric dry (ppmvd), corrected to 0% O_2, on a rolling 365-day average and 69.5 ppmvd, corrected to 0% O_2, on a rolling 7-day average. Per Paragraph 27 of the above-referenced CD, the 7-day NO_x emission limit established for the FCC shall not apply during periods of hydrotreater outages at the refinery, provided that ConocoPhillips is maintaining and operating its FCC (including associated air pollution control equipment) in a manner consistent with good air pollution control practices for minimizing emissions in accordance with the EPA-approved good air pollution control practices plan.

This action was ultimately put on hold until Operating Permit #OP2619-04 was issued; however, was assigned **Operating Permit #OP2619-05**.

On December 6, 2010, the Department received a request from ConocoPhillips to modify Operating Permit #OP2619-03 to include certain limits, standards, and obligations in response to agency requests and the requirements of Paragraph 210(a) contained the ConocoPhillips CD. ConocoPhillips also requested to include conditions pertaining to facility-related Supplemental Environmental Projects (SEP), although not specifically required by the ConocoPhillips CD. ConocoPhillips later rescinded the request to include these SEP conditions within this permit action. ConocoPhillips additionally requested removal of references to Tank #162 (Ground Water Interceptor System (GWIS) Recovered Oil Tank) as this tank has been taken out of service. With knowledge of forthcoming additional information and modification requests, in concurrence with ConocoPhillips, the Department withheld preparation and issuance of a revised Operating Permit; however, this action was assigned **Operating Permit #OP2619-06**.

Ultimately, the NCVU project was never implemented and the three-year time frame for construction to commence per ARM 17.8.762 lapsed. On August 29, 2011, the Department received a request from ConocoPhillips to withdraw Operating Permit #OP2619-04, including all requested conditions pertaining to the New Crude and Vacuum Unit.

Operating Permit #OP2619-04 has been withdrawn.

On September 19, 2011, the Department received a request from ConocoPhillips to incorporate the language from its July 28, 2011 MAQP modification request into Operating Permit #OP2613-03. No permit number was assigned as this was treated as supplementary to previous modification requests.

Modifications associated with ConocoPhillips' August 28, 2009, December 6, 2010, September 19, 2011 requests have been incorporated under the current permit action as has the acknowledgment of the withdrawal of Operating Permit #OP2619-04.

Operating Permit #OP2619-06 replaces Operating Permit #OP2619-03.

E. Taking and Damaging Analysis

HB 311, the Montana Private Property Assessment Act, requires analysis of every proposed state agency administrative rule, policy, permit condition or permit denial, pertaining to an environmental matter, to determine whether the state action constitutes a taking or damaging of private real property that requires compensation under the Montana or U.S. Constitution. As part of issuing an operating permit, the Department is required to complete a Taking and Damaging Checklist. As required by 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment.

YES	NO	
X		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	X	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	X	3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)
	X	4. Does the action deprive the owner of all economically viable uses of the property?
	X	5. Does the action require a property owner to dedicate a portion of property or to grant an easement? [If no, go to (6)].
		5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests?

YES	NO	
		5b. Is the government requirement roughly proportional to the impact of the proposed use of the property?
	X	6. Does the action have a severe impact on the value of the property? (consider economic impact, investment-backed expectations, character of government action)
	X	7. Does the action damage the property by causing some physical disturbance with respect to the property in excess of that sustained by the public generally?
	X	7a. Is the impact of government action direct, peculiar, and significant?
	X	7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded?
	X	7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question?
	X	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

Based on this analysis, the Department determined there are no taking or damaging implications associated with this permit action.

F. Compliance Designation

The last Full Compliance Evaluations and Compliance Monitoring Report (FCE/CMR) of the ConocoPhillips – Billings Refinery was August 19, 2010. ConocoPhillips was in compliance with permit limitations and conditions.

SECTION II. SUMMARY OF EMISSIONS UNITS

A. Facility Process Description

The Billings Refinery consists of the main refinery area, where crude is broken down into various petroleum products; a wastewater treatment facility; a tank farm; a coker unit; and the sulfur recovery facility. The truck loading rack, where gasoline and distillate is loaded into tank trucks, has been separated into a stand-alone Title V permit (OP4056-00).

B. Emission Units and Pollution Control Device Identification

Emission Unit 001 is the Boilers. The main boiler house stack brings together the emission gas streams from Boilers #1, #2, B-5, and B-6. This stack does not have control equipment, but it does have a CEMS for SO_2 and a volumetric flow rate monitor on the main stack, and NO_x, CO and O_2 CEMS for boilers B-5 and B-6. In addition, ConocoPhillips is permitted to operate a temporary boiler, which is included in this emitting unit.

Emission Unit 002 is the Fluid Catalytic Cracking Unit (FCCU) Stack. This stack carries emissions from the FCCU, which includes a regenerator. The FCCU does not have SO_2 control equipment, but does have a SO_2, CO, and O_2 CEMS, volumetric flow rate monitor and an opacity monitor.

Emission Unit 003 is a combination of the fuel gas combustion units at the refinery. The control on some of these units is Low and Ultra-Low NO_x burners. These units are also required to have a H_2S CEMS on the refinery fuel gas.

Emission Unit 004 is the PMA Unit which includes a Process Heater (H-3201). The PMA Storage Tank is included in UE008. This unit has a Low-NO_x burner with FGR. The heater shall burn only natural gas as fuel.

Emission Unit 005 is the Refinery Flare. This unit is actually considered a "control device" in and of itself. This particular flare is equipped with a steam injection system.

Emission Unit 006 is the Refinery Fugitive Emissions. This includes numerous units and is, for the most part, concerned with leaks. Controls are the seals, gaskets, packing, and plugs.

Emission Unit 007 is the SRU and associated equipment. This includes the Jupiter SRU flare, Claus units, and SRU incinerator. The flare is steam injected and the incinerator is equipped with low-NO_x burners. These units have a SO_2 CEMS, O_2, and volumetric flow rate monitor.

Emission Unit 008 is Storage Tanks. These tanks must meet requirements of floating roofs with seal systems, or fixed roofs with rooftop vacuum breaker vents. These units undergo regular inspections.

Emission Unit 009 was the Product Bulk Loading, which has been removed from the refinery's and moved to the Transportation Operation's permit (OP4056-00).

Emission Unit 010 is the Wastewater Treatment. This unit consists of various units and requires a CPI Separator with carbon canisters to reduce VOC emissions by 95%.

Emission Unit 011 is Miscellaneous Process Vents. This includes various units. Controls depend on the type of vent and include the use of a flare or combustion device, if controls are used.

Emission Unit 012 is the Catalytic Reforming Units #1 & #2.

SECTION III. PERMIT CONDITIONS

A. Emission Limits and Standards

Emission limits and standards in the Title V permit were established from the preconstruction permit, the Billings/Laurel SIP, NSPS requirements, NESHAP requirements, MACT requirements, and Supplemental Environmental Projects (SEPs). Section III.A.14 was added to the final Title V permit (the following conditions in that section were renumbered) and Section III.I.20(e) was clarified per the Settlement Stipulation and Order of Dismissal ordered on July 9, 2002 by the Board of Environmental Review. The Settlement Stipulation and Order of Dismissal were associated with Conoco's appeal of Title V permit OP2619-00.

B. Monitoring Requirements

ARM 17.8.1212(1) requires that all monitoring and analysis procedures or test methods, required under applicable requirements, be contained in operating permits. In addition, when the applicable requirement does not require periodic testing or monitoring, periodic monitoring must be prescribed that is sufficient to yield reliable data from the relevant time period that is representative of the source's compliance with the permit.

The requirements for testing, monitoring, recordkeeping, reporting, and compliance certification sufficient to assure compliance, does not require the permit to impose the same level of rigor for all emission units. Furthermore, it does not require extensive testing or monitoring to assure compliance with the applicable requirements for emission units that do not have significant potential to violate emission limitations or other requirements under normal operating conditions. When compliance with the underlying applicable requirement for an insignificant emission unit is not threatened by lack of regular monitoring and when periodic testing or monitoring is not otherwise required by the applicable requirement, the status quo **(i.e., no monitoring)** will meet the requirements of ARM 17.8.1212(1). Therefore, the permit does not include monitoring for insignificant emissions units.

The permit includes periodic monitoring or recordkeeping for each applicable requirement. The information obtained from the monitoring and recordkeeping will be used by the permittee to periodically certify compliance with the emission limits and standards. However, the Department may request additional testing to determine compliance with the emission limits and standards.

In the case of CEMS, and required back-up or alternative methods when the CEMS are not running, the permit states "the Department shall approve such contingency plans." When such contingency plans are in use and have been submitted, the source will be considered to be in compliance with the contingency plan requirement until the Department informs ConocoPhillips otherwise.

C. Test Methods and Procedures

The operating permit may not require testing for all sources if routine monitoring is used to determine compliance, but the Department has the authority to require testing if deemed necessary to determine compliance with an emission limit or standard. In addition, the permittee may elect to voluntarily conduct compliance testing to confirm its compliance status.

D. Recordkeeping Requirements

The permittee is required to keep all records listed in the operating permit as a permanent business record for at least 5 years following the date of the generation of the record.

E. Reporting Requirements

Reporting requirements are included in the permit for each emission unit and Section V of the operating permit "General Conditions" explains the reporting requirements. However, the permittee is required to submit semi-annual and annual monitoring reports to the Department and to annually certify compliance with the applicable requirements contained in the permit. The reports must include a list of all emission limit and monitoring deviations, the reason for any deviation, and the corrective action taken as a result of any deviation.

To eliminate redundant reporting, a source may reference previously submitted reports (with at least the date and subject of the report) in the semi-annual and annual reports instead of resubmitting the information in quarterly, and/or other reports. However, a source must still certify continuous or intermittent compliance with each applicable requirement annually.

F. Public Notice

In accordance with ARM 17.8.1232, a public notice was published in the *Billings Gazette* newspaper on or before October 20, 2011. The Department provided a 30-day public comment period on the draft operating permit from October 20, 2011 to November 21, 2011. ARM 17.8.1232 requires the Department to keep a record of both comments and issues raised during the public participation process. The comments and issues received are summarized below, along with the Department's responses.

Summary of Public Comments

Person/Group Commenting	Comment	Department Response
	No comments received.	

G. Draft Permit Comments

Summary of Permittee Comments

Permit Reference	Permittee Comment	Department Response
Section I	The Alternate Responsible Official is now Paul E. Seyler, (406) 255-7953	The Department incorporated the change as requested.
Section III.B	Conditions B.7, B.22, B.35, and B.41.f should be removed, due to the underlying regulation, state-only Heater/Boiler MACT rule, being removed from the state rules.	The Department incorporated the changes as requested.
Section III.D	Conditions D.19, D.32, D.39, D.45.e should be removed, due to the underlying regulation, state-only Heater/Boiler MACT rule, being removed from the state rules.	The Department incorporated the changes as requested.
Section III.E	Entire subsection should be removed, due to the dismantling and removal of the unit from the facility that is currently underway.	The Department incorporated the changes as requested with the understanding of dismantling and removal of the unit from the facility.

Summary of EPA Comments

Permit Reference	EPA Comment	Department Response
	No comments received.	

SECTION IV. FUTURE PERMIT CONSIDERATIONS

A. MACT Standards

As of the date of the Date of Decision, 40 CFR 63, Subpart CC, UUU, EEEE, DDDDD (State-only) are applicable to the ConocoPhillips Refinery. The Department is not aware of any proposed or pending MACT standard that may be applicable.

B. NESHAP Standards

As of the date of the Date of Decision, 40 CFR 61, Subparts M and FF, are applicable at the ConocoPhillips Refinery. The Department is not aware of any proposed or pending NESHAP standards that may be applicable.

C. NSPS Standards

The Department is not aware of any proposed or pending NSPS standards, in addition to those already listed, that may be applicable at this time.

D. Risk Management Plan

As of the date of the Date of Decision, this facility does exceed the minimum threshold quantities for any regulated substance listed in 40 CFR 68.115 for any facility process. Consequently, this facility is required to submit a Risk Management Plan.

If a facility has more than a threshold quantity of a regulated substance in a process, the facility must comply with 40 CFR 68 requirements no later than June 21, 1999; 3-years after the date on which a regulated substance is first listed under 40 CFR 68.130; or the date on which a regulated substance is first present in more than a threshold quantity in a process, whichever is later.

E. Compliance Assurance Monitoring (CAM) Plan

An emitting unit located at a Title V facility that meets the following criteria listed in ARM 17.8.1503 is subject to Subchapter 15 and must develop a CAM Plan for that unit:

- The emitting unit is subject to an emission limitation or standard for the applicable regulated air pollutant (other than emission limits or standards proposed after November 15, 1990, since these regulations contain specific monitoring requirements);
- The emitting unit uses a control device to achieve compliance with such limit; and
- The emitting unit has potential pre-control device emissions of the applicable regulated air pollutant that are greater than major source thresholds.

ConocoPhillips currently has one emitting unit that meets all the applicability criteria in ARM 17.8.1503: EU007 (Jupiter Sulfur Plant). The SRU/ATS unit is required to meet PM_{10} emission limitations. Filters on the SRU and ATS are used for PM_{10} control. ConocoPhillips proposes to use pressure drop across the filters as the on-going method of assuring compliance.

F. Alternate Operating Scenario

In accordance with the Consent Decree between ConocoPhillips and the EPA (Civil Action H-01-4430, as amended and entered on August 2, 2003), ConocoPhillips submitted Gas Oil Hydrotreater (GOH) outage plans for the Billings Refinery to minimize emissions of NO_x and SO_2 during GOH outages from the FCC Unit.

Appendix G of the Title V permit contains the Gas Oil Hydrotreater Outage Plan, Revision 5.1, dated March 15, 2006. This plan is incorporated into the Title V operating permit as an alternate operating scenario.

G. Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule

On May 7, 2010, EPA published the "light duty vehicle rule" (Docket # EPA-HQ-OAR- 2009-0472, 75 FR 25324) controlling greenhouse gas (GHG) emissions from mobile sources, whereby GHG became a pollutant subject to regulation under the Federal and Montana Clean Air Act(s). On June 3, 2010, EPA promulgated the GHG "Tailoring Rule" (Docket # EPA-HQ-OAR-2009-0517, 75 FR 31514) which modified 40 CFR Parts 51, 52, 70, and 71 to specify which facilities are subject to GHG permitting requirements and when such facilities become subject to regulation for GHG under the PSD and Title V programs.

Under the Tailoring Rule, any PSD action (either a new major stationary source or a major modification at a major stationary source) taken for a pollutant or pollutants other than GHG that would become final on or after January 2, 2011, would be subject to PSD permitting requirements for GHG if the GHG increases associated with that action were at or above 75,000 TPY of carbon dioxide equivalent (CO_2e) and greater than 0 TPY on a mass basis. Similarly, if such action were taken, any resulting requirements would be subject to inclusion in the Title V Operating Permit. Facilities which hold Title V permits due to criteria pollutant emissions over 100 TPY would need to incorporate any GHG applicable requirements into their operating permits for any Title V action that would have a final decision occurring on or after January 2, 2011.

Starting on July 1, 2011, PSD permitting requirements would be triggered for modifications that were determined to be major under PSD based on GHG emissions alone, even if no other pollutant triggered a major modification. In addition, sources that have not been considered PSD major sources based on criteria pollutant emissions would become PSD major sources if their facility-wide potential emissions equaled or exceeded 100,000 TPY of CO_2e and 100 or 250 TPY of GHG on a mass basis depending on their listed status in ARM 17.8.801(22). With respect to Title V, sources not currently holding a Title V permit that have potential facility-wide emissions equal to or exceeding 100,000 TPY of CO_2e and 100 TPY of GHG on a mass basis would be required to obtain a Title V Operating Permit.

Based on information provided by ConocoPhillips, the Billings Refinery potential emissions for the current listed emitting units exceed the GHG major source threshold of 100,000 tpy of CO_{2e} for both Title V and PSD under the Tailoring Rule. Therefore, ConocoPhillips may be subject to GHG permitting requirements in the future.

H. Other Considerations

The Department has reviewed the refinery (OP2619) and the bulk marketing terminal (OP4056) and has determined that for the purposes of MACT and New Source Review permitting, these facilities are one source. The refinery and the bulk marketing terminal are contiguous and adjacent, under common ownership and control and the terminal is a support facility to the refinery. Because the facilities meet these criteria, they meet the definition of source and will be considered one source under the requirements of ARM 17.8.749 and ARM 17.8.801(7). The emissions from both facilities will need to be considered when either facility makes a change.