Montana Department of
ENVIRONMENTAL QUALITY
Brian Schweitzer, Governor
P. O. Box 200901 Helena, MT 59620-0901 (406) 444-2544 Website: www.deq.mt.gov

November 3, 2008

Randall Richert, P.E., QEP
ConocoPhillips Company
Billings Refinery
P.O. Box 30198
Billings, MT 59107

Dear Mr. Richert:

The Department of Environmental Quality (Department) has made its decision on the Montana Air Quality Permit application for the New Crude and Vacuum Unit project. The application was given permit number 2619-24. The Department's decision may be appealed to the Board of Environmental Review (Board). A request for hearing must be filed by November 18, 2008. This permit shall become final on November 19, 2008, unless the Board orders a stay on the permit.

Procedures for Appeal: Any person jointly or severally adversely affected by the final action may request a hearing before the Board. Any appeal must be filed before the final date stated above. The request for a hearing shall contain an affidavit setting forth the grounds for the request. Any hearing will be held under the provisions of the Montana Administrative Procedures Act. Submit requests for a hearing in triplicate to: Chairman, Board of Environmental Review, P.O. Box 200901, Helena, Montana 59620.

Conditions: See attached.

For the Department,

Vickie Walsh

Vickie Walsh
Air Permitting Program Supervisor
Air Resources Management Bureau
(406) 444-3490

Moriah Peck

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VW: MAP:vs
Enclosures

AIR QUALITY PERMIT

Issued to:	ConocoPhillips Company Billings Refinery P.O. Box 30198 Billings, MT 59107-0198	Permit: #2619-24 Application Complete: 8/21/08 Preliminary Determination Issued: 9/24/08 Department's Decision Issued: 11/03/08 Permit Final: AFS#: 111-0011

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to ConocoPhillips Company - Billings Refinery (ConocoPhillips), pursuant to Sections 75-2-204, 211, and 215 of the Montana Code Annotated (MCA), as amended, and the Administrative Rules of Montana (ARM) 17.8.740, *et seq*., and 17.8.801, *et seq*., as amended, for the following:

SECTION I: Permitted Facilities

A. Plant Location – ConocoPhillips

ConocoPhillips operates a petroleum refinery located at 401 South 23rd Street, Billings, Montana, in the NW ¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County. A complete list of the permitted equipment for ConocoPhillips is contained in Section I.A of the Permit Analysis.

B. Plant Location - Jupiter Sulphur, LLC (Jupiter)

Jupiter operates a sulfur recovery facility, within the petroleum refinery area described above, at 2201 7th Avenue South, Billings, Montana. The facility is operated as a joint venture, of which ConocoPhillips is a partner. ConocoPhillips is responsible for maintaining air permit compliance at Jupiter's sulfur recovery facility. The Jupiter facility consists of three primary units: the Ammonium Thiosulfate (ATS) Plant, the Ammonium Sulfide Unit (ASD), and the Claus Sulfur and Tail Gas Treating Units (TGTUs). Jupiter's total sulfur recovery capacity is approximately 295 Long Tons per Day (LT/D) of sulfur, with a feed rate capacity from the ConocoPhillips' refinery of approximately 235 LT/D of sulfur. A complete list of the permitted equipment for Jupiter is contained in Section I.B of the Permit Analysis.

C. Current Permit Action

On August 21, 2008, the Department of Environmental Quality (Department) received a complete New Source Review – Prevention of Significant Deterioration permit application from ConocoPhillips. ConocoPhillips is proposing 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. The NCVU project will enable 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 will require modifications and optimization of the following existing process units: No. 2 Hydrodesulfurization (HDS) Unit, Saturate Gas Plant, No. 2 and No. 3 Amine Units, No. 5 HDS Unit, Coker Unit, No. 1 and 2 Hydrogen (H_2) Plants, Hydrogen Purification Unit (HPU), Raw Water Demineralizer System, Jupiter Sulfur Recovery Unit (SRU)/ATS Plant, and the Fluidized Catalytic Cracking Unit (FCCU). The primary objectives of the NCVU Project are 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 from the

refinery will need to be increased to approximately 235 LT/D of sulfur. With the submittal of this complete application, the minor source baseline dates for sulfur dioxide (SO_2), particulate matter (PM), and particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) have now been triggered in the Billings area as of August 21, 2008. The minor source baseline date for oxides of nitrogen (NO_x) was already triggered by Yellowstone Energy Limited Partnership (formerly Billings Generation Inc.) on November 8, 1991.

SECTION II: Conditions and Limitations

A. Applicable Requirements

1. ConocoPhillips shall comply with all applicable requirements of ARM 17.8.340, which reference 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):

a. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS Subpart as listed below

b. Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units shall apply to all affected boilers at the facility for which were constructed after June 19, 1984, are larger than 100 million British thermal units per hour (MMBtu/hr), and combust fossil fuel. ConocoPhillips shall comply with all applicable requirements of Subpart Db, for all affected boilers at the facility.

c. Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units shall apply to all affected boilers and steam generating units at the facility for which were constructed after June 9, 1989, are between 10 and 100 MMBtu/hr, and combust fossil fuel. ConocoPhillips shall comply with all applicable requirements of Subpart Dc, for all affected boilers and steam generating units at the facility.

d. Subpart J - Standards of Performance for Petroleum Refineries shall apply to, but not be limited to:

i. All of the heaters and boilers at the ConocoPhillips refinery (except those subject to Subpart Ja);

ii. The Claus units at the Jupiter sulfur recovery facility (until it becomes subject to Subpart Ja);

iii. The Refinery Main Plant Relief Flare. Compliance will be in accordance with 40 CFR 60.11(d) in lieu of the requirements of 40 CFR 60.104, 105 and 107 (Civil Action No. H-01-4430 ("ConocoPhillips Consent Decree"), Paragraphs 161 and 162);

iv. The Jupiter Sulfur Plant Flare (Jupiter Flare, also known as the SRU/Ammonium Sulfide Unit Flare) (ConocoPhillips Consent Decree, Paragraph 155 and 156) (until it becomes subject to Subpart Ja);

v. The FCCU (CO, SO_2, PM, and opacity provisions) (ConocoPhillips Consent Decree, Paragraph 54); and

vi. Any other affected equipment.

e. Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 shall apply to, but not be limited to:

i. New Crude Heater (H-2301);

ii. New Vacuum Heater (H-2401);

iii. Wastewater Treatment System Thermal Oxidizer (when firing supplemental refinery fuel gas (RFG));

iv. No. 1 H_2 Reformer Heater (H-9401);

v. Jupiter Sulfur Plant Flare (Jupiter Flare, also known as the SRU/Ammonium Sulfide Unit Flare);

vi. Jupiter Plant SRU;

vii. Jupiter Plant ATS Plant;

viii. Any other affected equipment.

f. Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids shall apply to all petroleum storage vessels for which construction, reconstruction or modification commenced after May 18, 1978, and prior to July 23, 1984, for requirements not overridden by 40 CFR 63, Subpart CC. These requirements shall be as specified in 40 CFR 60.110a through 60.115a. The affected tanks include, but are not limited to, the following:

Tank ID
T-100*
T-101*
T-102
T-104*

* *Currently exempt from all emission control provisions due to vapor pressure of materials stored.*

g. Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984, for requirements not overridden by 40 CFR 63, Subpart CC. These requirements shall be as specified in 40 CFR 60.110b through 60.117b. The affected tanks include, but are not limited to, the following:

Tank ID
T-35

T-36 (Currently out of service)
T-72
T-107*
T-110
T-162*
T-0851 (No.5 HDS Feed Storage Tank)
T-2909 (LSG Tank)
T-3201*

* *Currently exempt from all emission control provisions due to vapor pressure of materials stored.*

h. Subpart UU - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture shall apply to, but not be limited to, asphalt storage tank T-3201 and any other applicable storage tanks that commenced construction or modification after May 26, 1981. Asphalt storage tank T-3201 shall comply with the standards in 40 CFR 60.472(c).

i. Subpart GGG - Standards of Performance for Equipment Leaks of Volatile Organic Compound (VOC) in Petroleum Refineries shall apply to, but not be limited to:

- Delayed coker unit
- Cryogenic unit
- Hydrogen membrane unit
- Gasoline merox unit
- Crude vacuum unit (until no longer in service)
- Gas oil hydrotreater unit (consisting of a reaction section, fractionation section, and an amine treating section)
- No.1 H_2 Unit (22.0-million standard cubic feet per day (MMscfd) hydrogen plant feed system)
- Alkylation Unit Butane Defluorinator Project (consisting of heat exchangers; X-453, X-223, X-450, X-451, X-452, pumps; P-646, Vessels; D-130, D-359, D-360)
- Alkylation Unit Depropanizer Project
- Polymer Modified Asphalt (PMA) process unit
- #3 Sour Water Stripper (SWS) Unit
- Fugitive components associated with boilers #B-5 and #B-6
- The fugitive components associated with the No.2 H_2 Unit and the No.5 HDS Unit

- HPU and
- Any other applicable equipment constructed or modified after January 4, 1983

j. Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, shall apply to all of the fugitive VOC emitting components added in the NCVU project (including the NCVU off-gas compressor) and any other applicable equipment constructed, reconstructed, or modified after November 7, 2006.

k. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems, shall apply to, but not be limited to:

- Coker unit drain system
- Desalter wastewater break tanks
- Corrugated Plate Interceptor (CPI) separators
- Gas oil hydrotreater oily water sewer drain system
- No.1 H_2 Unit (22.0-MMscfd hydrogen plant)
- C-23 compressor station oily water sewer drain system
- Alkylation Unit Butane Defluorinator oily water sewer drain system
- Alkylation Unit Depropanizer oily water sewer drain system
- #3 SWS Unit oily water sewer drain system
- South Tank Farm oily water sewer drain system
- Tank T-4523 (wastewater surge tank)
- No.2 H_2 Unit and the No.5 HDS Unit new individual oily water drain system
- NCVU individual drain system
- two API separators associated with the NCVU Project and
- Any other applicable equipment, for requirements not overridden by 40 CFR 63, Subpart CC

2. ConocoPhillips shall comply with all applicable requirements of ARM 17.8.341, which references 40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAP):

a. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP subpart as listed below.

b. Subpart FF - National Emission Standards for Benzene Waste Operations shall apply to, but not be limited to, all new or recommissioned wastewater sewer drains associated with the Alkylation Unit Depropanizer Project, the Refinery's existing sewer system, the #3 SWS Unit, the new individual drain system for the waste streams associated with the No.2 H_2 Unit and the No.5 HDS Unit, Tanks 34 and 35, and all benzene-containing waste streams associated with the NCVU Project.

c. Subpart M - National Emission Standard for Asbestos shall apply to, but not be limited to, the demolition and/or renovation of regulated asbestos containing material.

3. ConocoPhillips shall comply with all applicable requirements of ARM 17.8.342, which reference 40 CFR Part 63, NESHAP for Source Categories, including the reporting, recordkeeping, and notification requirements:

a. Subpart A, General Provisions, applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

b. Subpart R, National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), shall apply to, but not be limited to, the bulk loading rack.

c. Subpart CC, National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries (Refinery MACT I), shall apply to, but not be limited to, Miscellaneous Process Vents; Storage Vessels; Wastewater Streams; Equipment Leaks; and the Gasoline Loading Rack.

d. Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (Refinery MACT II), shall apply to, but not be limited to, the FCCU and Catalytic Reforming Unit #2. Subpart UUU does not apply to the Catalytic Reforming Unit #1 as long as the reformer is dormant or the catalyst is regenerated off-site.

e. Subpart EEEE National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline) shall apply to, but not be limited to, Proto Gas storage tanks.

4. ConocoPhillips shall comply with the provisions of 40 CFR 82, Subpart F, Recycling and Emission Reduction as applicable.

B. Emission Control Requirements

ConocoPhillips shall install, operate, and maintain the following emission control equipment to provide the maximum air pollution control for which it was designed:

1. The Refinery Main Plant Relief flare must be equipped and operated with a steam injection system (ARM 17.8.752). The flare tip is to be based at a minimum of 142-feet plus or minus 2 feet elevation (ARM 17.8.749). ConocoPhillips shall minimize SO_2 flaring activity by installing and operating flare gas recovery systems on the Refinery Main Plant Relief flare (Consent Decree Paragraphs 162 and 163).

2. The Jupiter flare must be equipped and operated with a steam injection system (ARM 17.8.752). The flare tip is to be based at a minimum of 213-feet plus or minus 3 feet elevation (ARM 17.8.749).

3. Storage tank #49 shall be equipped with an internal floating roof with a double rim seal, liquid-mounted seal, or mechanical shoe seal system for VOC loss control (ARM 17.8.752).

4. Storage tanks #4510 and #4511 shall be equipped with internal floating roofs with double rim seals or a liquid-mounted seal system for VOC loss control (ARM 17.8.752).

5. Storage tank #162 shall be equipped with a fixed roof that includes a roof-top vacuum breaker vent (ARM 17.8.340).

6. All equipment subject to 40 CFR 60, Subpart GGG, as well as the C-23 Compressor Station (ARM 17.8.752), shall comply with the following:

    a. All valves used shall be high-quality valves containing high-quality packing.

    b. All open-ended valves shall be of the same quality as the valves described above. They will have plugs, caps or a second valve installed on the open end.

    c. All pipe and tower flanges shall be installed using process compatible gasket material.

    d. All pumps shall be fitted with the highest quality state-of-the-art mechanical seals, as appropriate.

    e. A monitoring and maintenance program as described under NSPS (40 CFR 60, Subpart VV) shall be instituted.

    f. For the C-23 compressor station, a VOC monitoring and maintenance program is instituted as described in 40 CFR 60.482-2, 40 CFR 60.482-4 thru 10, 40 CFR 60.483-1 and 2, 40 CFR 60.485, 40 CFR 60.486 (b-k), and 40 CFR 60.486 (c-e). If monitoring or scheduled inspections indicate failure or leakage of the compressor seal system, then the seals shall be repaired as soon as practicable (but not later than 15 calendar days after it is detected), except as provided in 40 CFR 60.482-9.

g. The affected equipment within the PMA process unit shall be visually monitored for equipment leaks as outlined in 40 CFR 60.482-8.

7. All equipment subject to 40 CFR 60, Subpart QQQ shall comply with all applicable requirements, including:

   a. All process drains shall consist of tightly sealed caps or P-leg traps for sewer drains with intermittent flow.

   b. The secondary oil/water separator is an oil/water (CPI) separator with hydrocarbon collection and recovery equipment.

   c. All equipment is operated and maintained as required by 40 CFR 60, Subpart QQQ.

8. All systems within the ConocoPhillips refinery and Jupiter sulfur recovery facility (modifications) shall be totally enclosed and controlled such that any pollutant generated does not vent to atmosphere, except as expressly allowed in this permit (ARM 17.8.749).

9. ConocoPhillips shall install and maintain the following burners:

   a. The recycle hydrogen heater (H-8401) and fractionator feed heater (H-8402) shall be equipped with Ultra Low NO_x Burner (ULNB).

   b. The No.1 H_2 Plant Reformer Heater (H-9401) and the No. 2 H_2 Plant Reformer Heater (H-9701) shall be equipped with ULNBs (ARM 17.8.752 and ARM 17.8.819).

   c. The Claus SRU Incinerator (F-304) shall be equipped with LNB (ARM 17.8.752 and ARM 17.8.819).

   d. The coker heater (H-3901) shall be equipped with LNB.[1]

   e. The PMA process heater (H-3201) shall be equipped with LNB with FGR.

   f. Boilers #B-5 and #B-6 shall be equipped with ULNB.

   g. No.5 HDS Charge Heater and No.5 HDS Stabilizer Reboiler Heater (EPN-41 and 42, respectively) shall be equipped with ULNB.

   h. The New Crude Heater (H-2301) and the New Vacuum Heater (H-2401) shall be equipped with Next Generation ULNBs (ARM 17.8.752 and ARM 17.8.819).

10. ConocoPhillips shall operate and maintain two CPI separator tanks with either carbon canister total VOC controls or a closed vent system routed to the wastewater treatment thermal oxidizer to comply with 40 CFR 60, Subpart QQQ, and 40 CFR 61, Subpart FF regulations. The CPI separators will be vented to either two carbon canisters in series, or the wastewater treatment thermal

[1] The low NO_X burners for the coker heater are a requirement of the coker Permit #2619 issued April 19, 1990.

oxidizer, designed and operated to reduce VOC emissions by 95%, or greater, with no detectable emissions.

11. The bulk loading gasoline and distillates loading rack shall be operated and maintained as follows:

    a. ConocoPhillips' loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from cargo tanks during product loading (ARM 17.8.342 and 40 CFR 63, Subpart R).

    b. ConocoPhillips' collected vapors shall be routed to the Vapor Combustor Unit (VCU) at all times. In the event the VCU was inoperable, ConocoPhillips may continue to load only distillates with a Reid vapor pressure of less than 27.6 kilopascals, provided the Department is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.752).

    c. The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the gasoline cargo tank from exceeding 4,500 Pascals (Pa) (450 millimeters (mm) of water) during product loading. This level shall not be exceeded when measured by the procedures specified in the test methods and procedures in 40 CFR 60.503(d) (ARM 17.8.342 and 40 CFR 63, Subpart R).

    d. No pressure vacuum vent in the permitted terminal's vapor collection system shall begin to open at a system pressure less than 4,500 Pa (450 mm of water) (ARM 17.8.342 and 40 CFR 63, Subpart R).

    e. The vapor collection system shall be designed to prevent VOC vapors collected at one loading position from passing to another loading position (ARM 17.8.342 and 40 CFR 63, Subpart R).

    f. Loading of liquid products into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks using the following procedures (ARM 17.8.342 and 40 CFR 63, Subpart R):

        i. ConocoPhillips shall obtain annual vapor tightness documentation described in the test methods and procedures in 40 CFR 63.425(e) for each gasoline cargo tank that is to be loaded at the loading rack.

        ii. ConocoPhillips shall require the cargo tank identification number to be recorded as each gasoline cargo tank is loaded at the terminal.

        iii. ConocoPhillips shall cross check each tank identification number obtained during product loading with the file of tank vapor tightness documentation within 2 weeks after the corresponding cargo tank is loaded.

iv. ConocoPhillips shall notify the owner or operator of each non-vapor-tight cargo tank loaded at the loading rack within 3 weeks after the loading has occurred.

v. ConocoPhillips shall take the necessary steps to ensure that any non-vapor-tight cargo tank will not be reloaded at the loading rack until vapor tightness documentation for that cargo tank is obtained which documents that:

a. The gasoline cargo tank meets the applicable test requirements in 40 CFR 63.425(e) of this permit.

b. For each gasoline cargo tank failing the test requirements in 40 CFR 63.425(f) or (g), the gasoline cargo tank must either:

i. Before the repair work is performed on the cargo tank, meet the test requirements in 40 CFR 63.425 (g) or (h).

ii. After repair work is performed on the cargo tank before or during the tests in 40 CFR 63.425 (g) or (h), subsequently passes, the annual certification test described in 40 CFR 63.425(e).

g. ConocoPhillips shall ensure that gasoline cargo tanks at the loading rack are loaded only into cargo tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system (ARM 17.8.342 and 40 CFR 63, Subpart R).

h. ConocoPhillips shall ensure that the terminal and the cargo tank vapor recovery systems are connected during each loading of a gasoline cargo tank at the loading rack (ARM 17.8.342 and 40 CFR 63, Subpart R).

i. Loading of cargo tanks shall be restricted to the use of submerged fill and dedicated normal service (ARM 17.8.749).

j. ConocoPhillips shall install and continuously operate a thermocouple and an associated recorder for temperature monitoring in the firebox or ductwork immediately downstream in a position before any substantial heat occurs, and develop an operating parameter value for the VCU in accordance with the provisions of 40 CFR 63.425 and 63.427 (ARM 17.8.342 and 40 CFR 63, Subpart R; and ARM 17.8.752).

k. ConocoPhillips shall perform a monthly leak inspection of all equipment in gasoline service. The inspection must include, but is not limited to, all valves, flanges, pump seals, and open-ended lines. For purposes of this inspection, detection methods incorporating sight, sound, or smell are acceptable. Each piece of equipment shall be inspected during the loading of a gasoline cargo tank (ARM 17.8.342 and 40 CFR 63, Subpart R).

l. A logbook shall be used and shall be signed by the owner or operator at the completion of each inspection. A section of the log shall contain a list,

summary description, or diagram(s) showing the location of all equipment in gasoline service at the facility (ARM 17.8.342 and 40 CFR 63, Subpart R).

m. Each detection of a liquid or vapor leak shall be recorded in the logbook. When a leak is detected, an initial attempt at repair shall be made as soon as practicable, but no later than 5 calendar days after the leak is detected. Repair or replacement of leaking equipment shall be completed within 15 calendar days after detection of each leak, except as provided in "n" below (ARM 17.8.342 and 40 CFR 63, Subpart R).

n. Delay of repair of leaking equipment will be allowed upon a demonstration to the Department that repairs within 15 days are not feasible. The owner or operator shall provide the reason(s) a delay is needed and the date by which each repair is expected to be completed (ARM 17.8.342 and 40 CFR 63, Subpart R).

o. ConocoPhillips shall not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

i. Minimize gasoline spills;

ii. Clean up spills as expeditiously as practicable;

iii. Cover all open gasoline containers with a gasketed seal when not in use and;

iv. Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators (ARM 17.8.342 and 40 CFR 63, Subpart R).

12. Jupiter shall vent off-gas from the ASD unit operation to the B304 sulfur boiler except during malfunction or maintenance conditions, when the off-gases would be vented to the Jupiter SRU flare (ARM 17.8.749).

13. ConocoPhillips shall operate a temporary natural gas-fired boiler for up to 8 weeks per rolling 12-month period. Any temporary boiler constructed, modified, or reconstructed after June 9, 1989, shall comply with the provisions of 40 CFR Part 60, Subpart Dc. The temporary boiler will not exceed a firing rate of 51 MMBtu/hr, and will only be used during refinery turnarounds (ARM 17.8.749).

14. ConocoPhillips shall operate and maintain an amine-based chemical absorption system on the refinery fuel gas system (ARM 17.8.752 and ARM 17.8.819).

15. The Claus SRU shall be equipped with a TGTU (ARM 17.8.752 and ARM 17.8.819).

16. The New Cooling Water Tower (CWT-2501) shall be equipped with a high efficiency drift eliminator (ARM 17.8.752 and ARM 17.8.819).

17. ConocoPhillips shall install, operate, and maintain a thermal oxidizer on the new wastewater treatment facility to provide the maximum air pollution control for which it is designed (ARM 17.8.752 and ARM 17.8.819).

18. ConocoPhillips shall utilize an optimized fuel-to-air ratio to promote complete combustion in the thermal oxidizer (ARM 17.8.752 and ARM 17.8.819).

19. ConocoPhillips shall install a fixed roof on the API separators and Dissolved Air Floatation (DAF) vessel. A vapor collection system shall be installed to collect and route emissions from the enclosed vapor space in the API separators and DAF vessel system to the wastewater treatment system thermal oxidizer (ARM 17.8.752).

20. Within 180 days of startup of the New Crude and Vacuum Units, the old crude and vacuum units (H-1, H-17, and H-24) shall be permanently shutdown (ARM 17.8.749).

C. Emission Limitations

1. Total refinery and sulfur recovery facility emissions shall not exceed the following:

a. <u>Jupiter SRU/ATS Main Stack (S-101/S-401)</u>

i. SO_2 Emissions –

- 25.00 pounds per hour (lbs/hr) (ARM 17.8.749)
- 167 ppmv, corrected to 0% O_2 on a dry basis, on a rolling 12-hour average
- Following the startup of the New Crude and Vacuum Units: 150 ppmv, corrected to 0% O_2 on a dry basis, on a rolling 365-day average (ARM 17.8.752 and ARM 17.8.819)
- 0.30 tons/day
- Following the startup of the New Crude and Vacuum Units: 98.35 tons per year (TPY) (ARM 17.8.749)

ii. NO_X Emissions - 18.92 lbs/hr, 454.0 lbs/day, 82.85 TPY (ARM 17.8.749)

iii. Prior to startup of the New Crude and Vacuum Units: PM_{10} Emissions – 7.76 lbs/hr, 186.3 pounds per day (lb/day), 34.00 TPY

iv. Following startup of the New Crude and Vacuum Units: PM_{10} Emissions - 6.26 lbs/hr, 186.3 lb/day, 27.42 TPY (ARM 17.8.749)

v. CO Emissions - 0.40 lb/hr, 1.76 TPY (ARM 17.8.749)

vi. Ammonia - 13.36 lbs/hr, 320.5 lb/day, 58.5 TPY

vii. Opacity - 20% averaged over any 6 consecutive minutes

b. Jupiter SRU Flare[2]

i. SO_2 Emissions - 25.00 lbs/hr, 0.30 tons/day (ARM 17.8.749).

ii. Hydrogen Sulfide (H_2S) content of the flare fuel gas (and pilot gas) burned shall not exceed 0.10 grain/dry standard cubic foot (gr/dscf) (ARM 17.8.749), with the exception of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions (ARM 17.8.340, 40 CFR 60, Subpart J, and 40 CFR 60, Subpart Ja).

iii. PM and CO emissions shall be kept to their negligible levels as indicated in the permit application (ARM 17.8.749).

iv. Opacity - 20% averaged over any 6 consecutive minutes (ARM 17.8.749).

c. Total SO_2 emissions from the Jupiter SRU/ATS main stack plus the Jupiter SRU flare shall not exceed 109.5 TPY (rolling 12-month average) (ARM 17.8.749).

d. FCCU Stack

i. SO_2 Emissions - 328.8 lbs/hr, rolling 24-hour average; 3.945 ton/day; 48.86 TPY (ARM 17.8.749).

ii. SO_2 Emissions – SO_2 emissions from the FCCU shall not exceed 25 ppmvd at 0% O_2 based on a rolling 365-day average, as well as 50 ppmvd at 0% O_2 based on a rolling 7-day average. The 7-day SO_2 emission limit shall not apply during periods of No.4 hydrotreater (GOHDS Unit) outages, provided that ConocoPhillips is maintaining and operating its FCCUs (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 plan (ConocoPhillips Consent Decree, Paragraphs 40-42). The SO_2 emissions started contributing to both averages (365-day and 7-day) beginning on December 31, 2005.

iii. SO_2 Emissions from FCCU shall not exceed 9.8 kilograms per Megagram (kg/Mg, or 20 lb/ton) coke burnoff on a 7-day rolling average basis, in accordance with 40 CFR 60.104(b)(2) and (c). As an alternative, ConocoPhillips shall process in the FCCU fresh feed that has a total sulfur content no greater than 0.30 percent by weight on a 7-day rolling average basis, in accordance with 40 CFR 60.104(b)(3) and (c). This limit became effective on February 1, 2005 (ConocoPhillips Consent Decree Paragraph 54, and 40 CFR 60, Subpart J).

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[2] Emissions occur only during times that the ATS plant is not operating.

iv. CO Emissions – 150 ppmvd at 0% O_2 based on a rolling 365-day average basis (ConocoPhillips Consent Decree, Paragraph 50)

v. CO Emissions – 500 ppmvd at 0% O_2 based on a one-hour average emission limit. CO emissions during periods of startup, shutdown or malfunctions of the FCCU will not be used for determining compliance with this emission limit, provided that ConocoPhillips implements good air pollution control practices to minimize CO emissions (ConocoPhillips Consent Decree, Paragraph 49, as amended).

vi. Following startup of the New Crude and Vacuum Units: CO emissions from the FCCU shall not exceed 26.54 lbs/hr and 116.25 TPY (ARM 17.8.749).

vii. PM Emissions - the FCCU shall not exceed the PM limit of 1 lb/1000 lbs coke burned (ConocoPhillips Consent Decree, Paragraph 46 and 54, ARM 17.8.340 and 40 CFR 60, Subpart J).

viii. Opacity – not to exceed 30%, except for one 6-minute average in any 1 hour period (ConocoPhillips Consent Decree, Paragraph 54, ARM 17.8.340 and 40 CFR 60, Subpart J).

e. Refinery Fuel Gas Heaters/Furnaces

i. ConocoPhillips shall not burn fuel oil in any of its heaters (ARM 17.8.749).

ii. Combined SO_2 Emissions shall not exceed: 614 lb/day, rolling 24-hour average; and 45.5 TPY, rolling 12-month average for the following fuel gas combustion units (ARM 17.8.749):

- Prior to startup of the New Crude and Vacuum Units: Emission Point 2, H-1;
- Emission Point 3, H-2;
- Emission Point 4, H-4;
- Emission Point 5, H-5;
- Emission Point 7, H-10 – No. 2 HDS;
- Emission Point 8, H-11 – No. 2 HDS Debutanizer Reboiler;
- Emission Point 9, H-12 – No. 2 HDS Main Frac. Reboiler;
- Emission Point 10, H-13 – Catalytic Reforming Unit #2;
- Emission Point 11, H-14 – Catalytic Reforming Unit #2;
- Emission Point 12, H-15;

- Emission Point 13, H-16 – Saturated Gas Stabilizer Reboiler and PB Merox Disulfide Offgas;
- Prior to startup of the New Crude and Vacuum Units: Emission Point 14, H-17;
- Emission Point 15, H-18;
- Emission Point 16, H-19;
- Emission Point 17, H-20;
- Emission Point 18, H-21;
- Emission Point 20, H-23 – Catalytic Reforming Unit #2;
- Prior to startup of the New Crude and Vacuum Units: Emission Point 21, H-24;
- Following startup of the New Crude and Vacuum Units: Emission Point 48, H-2301 – New Crude Heater;
- Following startup of the New Crude and Vacuum Units: Emission Point 49, H-2401 – New Vacuum Heater;
- Emission Point 6, H-3901 – Coke Heater;
- Emission Point 28, H-8401 – Recycle Hydrogen Heater;
- Emission Point 29, H-8402 – Fractionator Feed Heater;
- Following startup of the New Crude and Vacuum Units: Emission Point 35, H-9401 - No. 1 H_2 Plant Reformer Heater; and
- Following startup of the New Crude and Vacuum Units: Emission Point 43, H-9701 - No. 2 H_2 Plant Reformer Heater.

iii. H_2S content of fuel gas burned shall not exceed 0.10 gr/dscf, rolling 3-hr average.

iv. H_2S content of fuel gas shall not exceed 0.073 gr/dscf (116.5 ppmv H_2S) per rolling 12-month time period (ARM 17.8.749), for fuel gas burned in:

- Prior to startup of the New Crude and Vacuum Units, Emission point 35, H-9401, the No. 1 H_2 Reformer Heater
- Emission point 7, H-10, the No. 2 HD
- Emission point 8, H-11, the Debutanizer Reboiler, No. 2 HDS

- Emission point 9, H-12, the Main Frac. Reboiler No. 2 HDS
- Emission point 10, H-13, Catalytic Reforming Unit #2
- Emission point 11, H-14, Catalytic Reforming Unit #2
- Emission point 13, H-16, the Stabilizer Reboiler, Sat Gas
- Emission point 20, H-23, Catalytic Reforming Unit #2
- Emission point 41, No.5 HDS Charge Heater
- Emission point 42, No.5 HDS Stabilizer Reboiler Heater
- Prior to startup of the New Crude and Vacuum Units, Emission point 43, No. 2 H_2 Reformer Heater

v. During periods of startup and shutdown of the refinery fuel gas treatment system, the H_2S content of the fuel gas burned in the New Crude Heater (H-2301) and the New Vacuum Heater (H-2401) shall not exceed 162 ppmv (3-hour rolling average). Otherwise, the H_2S content of the fuel gas burned in these units shall not exceed 34 ppmv based on a rolling 365-day average (ARM 17.8.752 and ARM 17.8.819).

vi. Following original startup of the New Crude and Vacuum Units: During periods of startup and shutdown of the refinery fuel gas treatment system, the H_2S content of the fuel gas burned in the No. 1 H_2 Plant Reformer Heater (H-9401) and the No. 2 H_2 Plant Reformer Heater (H-9701) shall not exceed 162 ppmv (3-hour rolling average). Otherwise, the H_2S content of the fuel gas burned in these units shall not exceed 34 ppmv based on a rolling 365-day average (ARM 17.8.752 and ARM 17.8.819).

vii. Opacity from each of the Refinery Fuel Gas Heaters/Furnaces constructed prior to 1968 shall not exceed 40% averaged over any 6 consecutive minutes (ARM 17.8.304).

viii. Opacity from each of the Refinery Fuel Gas Heaters/Furnaces constructed after 1968, including the No.5 HDS Charge Heater, No.5 HDS Stabilizer Reboiler Heater, No.2 H_2 Plant Reformer Heater (H-9701), Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, No. 1 H_2 Plant Reformer Heater (H-9401), H-1, New Crude Heater (H-2301), and New Vacuum Heater (H-2401) shall each not exceed 20% averaged over 6 consecutive minutes (ARM 17.8.304).

ix. NO_X emissions from the No.5 HDS Charge Heater shall not exceed 0.03 pound per million British thermal units (lb/MMBtu) per rolling 12-month time period (ARM 17.8.752).

x. CO emissions from the No.5 HDS Charge Heater shall not exceed 0.317 lb/MMBtu per rolling 12-month time period when the heater is operating at 10.9 MMBtu/hr or less (ARM 17.8.752).

xi. CO emissions from the No.5 HDS Charge Heater shall not exceed 0.1585 lb/MMBtu per rolling 12-month time period when the heater is operating at greater than 10.9 MMBtu/hr (ARM 17.8.752).

xii. NO_X emissions from the No.5 HDS Stabilizer Reboiler Heater shall not exceed 0.03 lb/MMBtu per rolling 12-month time period (ARM 17.8.752).

xiii. CO emissions from the No.5 HDS Stabilizer Reboiler Heater shall not exceed 0.1585 lb/MMBtu per rolling 12-month time period when the heater is operating at 29.9 MMBtu/hr or less (ARM 17.8.752).

xiv. CO emissions from the No.5 HDS Stabilizer Reboiler Heater shall not exceed 0.091 lb/MMBtu per rolling 12-month time period when the heater is operating at greater than 29.9 MMBtu/hr (ARM 17.8.752).

xv. Following startup of the New Crude and Vacuum Units: PM_{10} emissions from the No. 1 H_2 Plant Reformer Heater (H-9401) shall not exceed 1.98 lbs/hr and 8.68 TPY (ARM 17.8.749).

xvi. Following startup of the New Crude and Vacuum Units: CO emissions from the No. 1 H_2 Plant Reformer Heater (H-9401) shall not exceed 3.99 lbs/hr and 17.47 TPY (ARM 17.8.749).

xvii. Following startup of the New Crude and Vacuum Units: VOC emissions from the No. 1 H_2 Plant Reformer Heater (H-9401) shall not exceed 0.22 lbs/hr and 0.98 TPY (ARM 17.8.749).

xviii. Following startup of the New Crude and Vacuum Units: PM_{10} emissions from the No. 2 H_2 Plant Reformer Heater (H-9701) shall not exceed 1.60 lbs/hr and 7.02 TPY (ARM 17.8.749).

xix. Following startup of the New Crude and Vacuum Units: CO emissions from the No. 2 H_2 Plant Reformer Heater (H-9701) shall not exceed 3.23 lbs/hr and 14.13 TPY (ARM 17.8.749).

xx. Following startup of the New Crude and Vacuum Units: VOC emissions from the No. 2 H_2 Plant Reformer Heater (H-9701) shall not exceed 0.48 lbs/hr and 2.12 TPY (ARM 17.8.749).

xxi. The PSA purge gas used as heater fuel in the No. 2 H_2 Plant Reformer Heater (H-9701) shall be sulfur free (ARM 17.8.752).

xxii. Prior to startup of the New Crude and Vacuum Units: The total NO_X emissions from the No.5 HDS Charge Heater (H-9501),

the No.5 HDS Stabilizer Reboiler Heater (H-9502), and the No.2 H_2 Plant Reformer Heater (H-9701) shall not exceed 7.95 lbs/hr and 34.19 TPY (ARM 17.8.752).

xxiii. Following startup of the New Crude and Vacuum Units: The total NO_X emissions from the No.5 HDS Charge Heater (H-9501), the No.5 HDS Stabilizer Reboiler Heater (H-9502), and the No.2 H_2 Plant Reformer Heater (H-9701) shall not exceed 8.67 lbs/hr and 37.99 TPY (ARM 17.8.752).

xxiv. NO_X emissions from the No. 1 H_2 Plant Reformer Heater (H-9401) and the No.2 H_2 Plant Reformer Heater (H-9701) shall not exceed 0.03 lb/MMBtu per rolling 12-month time period (ARM 17.8.752 and ARM 17.8.819).

xxv. Following startup of the New Crude and Vacuum Units: During periods of startup and shutdown of the No. 1 H_2 Plant Reformer Heater (H-9401) and the No. 2 H_2 Plant Reformer Heater (H-9701), CO emissions shall not exceed a daily average of 1.7 lb/MMBtu. Otherwise, the CO emissions from these units shall not exceed 0.015 lb/MMBtu based on a rolling 365-day average (ARM 17.8.752).

xxvi. NO_X emissions from the Coker Heater (H-3901) shall not exceed 0.08 lb/MMBtu and 7.38 lbs/hr (ARM 17.8.752).

xxvii. NO_X emissions from the Recycle Hydrogen Heater (H-8401) shall not exceed 0.03 lb/MMBtu (ARM 17.8.752).

xxviii. NO_X emissions from the Fractionator Feed Heater (H-8402) shall not exceed 0.03 lb/MMBtu (ARM 17.8.752).

xxix. Prior to startup of the New Crude and Vacuum Units: The total NO_X emissions from the Coker Heater (H-3901), Recycle Hydrogen Heater (H-8401), Fractionator Feed Heater (H-8402), and the No. 1 H_2 Plant Reformer Heater (H-9401) shall not exceed 13.54 lbs/hr and 58.95 TPY (ARM 17.8.752).

xxx. Following startup of the New Crude and Vacuum Units: The total NO_X emissions from the Coker Heater (H-3901), Recycle Hydrogen Heater (H-8401), Fractionator Feed Heater (H-8402), and the No. 1 H_2 Plant Reformer Heater (H-9401) shall not exceed 14.49 lbs/hr and 63.45 TPY (ARM 17.8.752).

xxxi. NO_x emissions from the New Crude Heater (H-2301) shall not exceed 6.44 lbs/hr and 28.19 TPY (ARM 17.8.749).

xxxii. PM_{10} emissions from the New Crude Heater (H-2301) shall not exceed 1.23 lbs/hr and 5.38 TPY (ARM 17.8.749).

xxxiii. CO emissions from the New Crude Heater (H-2301) shall not exceed 1.82 lbs/hr and 7.95 TPY (ARM 17.8.749).

xxxiv. VOC emissions from the New Crude Heater (H-2301) shall not exceed 0.89 lbs/hr and 3.90 TPY (ARM 17.8.749).

xxxv. NO_x emissions from the New Vacuum Heater (H-2401) shall not exceed 2.26 lbs/hr and 9.91 TPY (ARM 17.8.749).

xxxvi. PM_{10} emissions of the New Vacuum Heater (H-2401) shall not exceed 0.43 lbs/hr and 1.89 TPY (ARM 17.8.749).

xxxvii. CO emissions from the New Vacuum Heater (H-2401) shall not exceed 0.64 lbs/hr and 2.79 TPY (ARM 17.8.749).

xxxviii. VOC emissions from the New Vacuum Heater (H-2401) shall not exceed 0.31 lbs/hr and 1.37 TPY (ARM 17.8.749).

xxxix. NO_x emissions from the New Crude Heater (H-2301) and New Vacuum Heater (H-2401) shall not exceed 0.039 lbs/MMBtu per rolling 12-month time period (ARM 17.8.752 and ARM 17.8.819).

xl. PM_{10} and $PM_{2.5}$ emissions from the New Crude Heater (H-2301), New Vacuum Heater (H-2401), No. 1 H_2 Plant Reformer Heater (H-9401) and No. 2 H_2 Plant Reformer Heater (H-9701) shall not exceed 0.0075 lb/MMBtu per rolling 12-month time period (ARM 17.8.752 and ARM 17.8.819).

xli. During periods of startup and shutdown of the New Crude Heater (H-2301) and the New Vacuum Heater (H-2401), CO emissions shall not exceed a daily average of 0.30 lb/MMBtu. Otherwise, the CO emissions shall not exceed 0.011 lb/MMBtu based on a rolling 365-day average (ARM 17.8.752).

f. <u>Main Boilerhouse Stack</u>

i. SO_2 Emissions - 321.4 lbs/hr, rolling 24-hour average; 3.857 ton/day; 1,407.8 TPY (fuel oil and fuel gas combustion).

ii. SO_2 Emissions – 300 TPY from fuel oil combustion, based on a rolling 365-day average as determined by the existing SO_2 Continuous Emissions Monitoring System (CEMS) or replacement SO_2 CEMS subsequently installed and certified (ConocoPhillips Consent Decree, Paragraph 71).

iii. H_2S content of fuel gas burned shall not exceed 0.10 gr/dscf, rolling 3-hr average.

iv. H_2S content of fuel gas burned in boilers #B-5 and #B-6 shall not exceed 96 ppmv on a rolling 365-day average (ARM 17.8.749).

v. Opacity - 40% averaged over any 6 consecutive minutes, except during times that the exhaust from only boilers #B-5 and #B-6 are being routed to the main boiler stack, the opacity limit is 20% (ARM 17.8.340).

vi. NO_X emissions from boilers #B-5 and #B-6 shall each, when fired on RFG, not exceed 0.03 lb/MMBtu based on a rolling 365-day average or 24.05 TPY based on a rolling 365-day average. Compliance with the limits shall be monitored with the NO_X and O_2 CEMS subsequently installed and certified (ARM 17.8.752).

vii. CO emissions from boilers #B-5 and #B-6 shall each not exceed 0.04 lb/MMBtu based on a rolling 365-day average fired on RFG (ARM 17.8.752).

viii. VOC Emissions from boilers #B-5 and #B-6 shall each not exceed 4.32 tons/rolling 12-calendar month total (ARM 17.8.752).

g. PMA Process Heater Stack (H-3201)

i. NO_X emissions shall not exceed 80 pounds per million standard cubic feet (lb/MMscf) or 0.76 lb/hr (ARM 17.8.752).

ii. The PMA Process Heater shall be fired on purchased natural gas only and shall not be fired on RFG.

iv. Opacity - 20% averaged over any 6 consecutive minutes.

v. Heater stack shall be a minimum of 50 feet in height above grade, when the PMA Process Heater is operating.

h. PMA Storage Tank Vent

Opacity shall not exceed 0%, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown clear (40 CFR 60.472(c)).

i. Wastewater Treatment System Thermal Oxidizer

i. ConocoPhillips shall not cause or authorize to be discharged into the atmosphere from the wastewater treatment system thermal oxidizer:

a. Any visible emissions that exhibit an opacity of 10% or greater averaged over 6 consecutive minutes (ARM 17.8.752 and ARM 17.8.819); and

b. Any particulate matter emissions in excess of 0.10 gr/dscf, adjusted to 12% CO_2 and calculated as if no auxiliary fuel had been used (ARM 17.8.752).

ii. During periods of startup and shutdown of the wastewater treatment system thermal oxidizer, NO_x emissions shall not exceed 1,000 ppmv at 8% O_2 on a rolling 365-day average. Otherwise, the NO_x emissions shall not exceed 25 ppmv at 8% O_2 on a rolling 365-day average (ARM 17.8.752 and ARM 17.8.819).

iii. During periods of startup and shutdown of the wastewater treatment system thermal oxidizer, the H_2S content of the fuel gas burned in this unit shall not exceed 162 ppmv (3-hour rolling average). Otherwise, the H_2S content of the fuel gas burned in this unit shall not exceed 34 ppmv based on a rolling 365-day average (ARM 17.8.752 and ARM 17.8.819).

iv. PM_{10} and $PM_{2.5}$ emissions from the wastewater treatment system thermal oxidizer shall not exceed 0.011 lb/hr (ARM 17.8.752 and ARM 17.8.819).

v. During periods of startup and shutdown of the wastewater treatment system thermal oxidizer, CO emissions shall not exceed 1,000 ppmv at 8% O_2 on a rolling 365-day average. Otherwise, the CO emissions shall not exceed 25 ppmv at 8% O_2 on a rolling 365-day average (ARM 17.8.752).

j. New Cooling Water Tower (CWT-2501)

i. Total liquid drift shall not exceed 0.0005% of the circulating water flow rate (ARM 17.8.752 and ARM 17.8.819).

ii. ConocoPhillips shall implement a monitoring, inspection, and maintenance plan of the new cooling water tower (ARM 17.8.752).

k. Total SO_2 emissions for refinery and sulfur recovery facilities shall not exceed the limit of 3,103 TPY (Sections II.C.1.a – i and II.C.6). In addition, where applicable, all other federal emission limitations shall be met (ARM 17.8.749).

2. All access roads shall use either paving or chemical dust suppression as appropriate to limit excessive fugitive dust, with water as a back-up measure, to maintain compliance with ARM 17.8.308 and the 20% opacity limitation. ConocoPhillips shall use reasonable precautions during construction, and earth-moving activities shall use reasonable precautions to limit excessive fugitive dust and to mitigate impacts to nearby residential and commercial places (ARM 17.8.308).

3. Emissions from the loading of gasoline and distillates at the loading rack shall be limited to the following:

a. The total VOC emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 milligrams per liter (mg/L) of gasoline loaded (ARM 17.8.342; 40 CFR 63, Subpart R; and ARM 17.8.752).

b. The total CO emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.752).

c. The total NO_X emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 4.0 mg/L of gasoline loaded (ARM 17.8.752).

d. ConocoPhillips shall not cause or authorize to be discharged into the atmosphere from the enclosed VCU:

i. Any visible emissions that exhibit an opacity of 10% or greater (ARM 17.8.749)

ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO_2 (ARM 17.8.749)

4. ConocoPhillips shall operate and maintain the Saturate Gas Plant according to the Leak Detection and Repair (LDAR) program. ConocoPhillips shall monitor and maintain all pumps, shutoff valves, relief valves, and other piping and valves associated with the Saturate Gas Plant, as described in 40 CFR 60.482-1 through 60.482-10. Records of monitoring and maintenance shall be maintained on site for a minimum of 5 years (ARM 17.8.342, 40 CFR 63, Subpart CC and ARM 17.8.752).

5. ConocoPhillips shall operate and maintain all new (associated with the Low Sulfur Gasoline (LSG) project) fugitive component VOC emissions in the No.2 HDS Unit, the Gas Oil Hydrodesulfurizer (GOHDS) Unit, and the Tank Farm (including those fugitive emissions associated with the LSG tank) according to the LDAR program (ARM 17.8.342; 40 CFR 63, Subpart CC; and ARM 17.8.752).

6. <u>Refinery Main Plant Relief Flare Stack</u>

a. ConocoPhillips shall meet the 40 CFR 60, Subpart A & J requirements by installing and operating a flare gas recovery system (FGRS), as a means of implementing good air pollution control practices in accordance with 40 CFR 60.11(d) in lieu of meeting the emission limits and monitoring and recordkeeping requirements of 40 CFR 60.104, 105, and 107. ConocoPhillips shall operate the FGRS at all times that the facility is operating, except during any reasonably required maintenance on the flare system and/or the FGRS, or during periods of maintenance that would result in the frequent starting-up and shutting-down for the FGRS; the FGRS is shutdown for safety reasons; or it cannot effectively be operated due to the shutdown or operational problems associated with one or more units (ARM 17.8.749; ConocoPhillips Consent Decree Paragraph 162; Montana Consent Decree Paragraph 44, as amended).

b. For any acid gas, hydrocarbon, or tail gas flaring incident that results in emission of SO_2 that are equal or greater than 500 lbs in a 24-hour period, ConocoPhillips will prepare a Root Cause Failure Analysis (RCFA) and corrective action (ARM 17.8.749 and ConocoPhillips Consent Decree Paragraphs 154, 156, 160, 160A, 160B, 161, 162, and 163).

c. SO_2 emission increases, due to upset conditions or discontinuance of the SRU, shall be offset by an equivalent rate from any other sources covered by this permit.

7. Jupiter Flare

Prior to modification of the Jupiter Flare, ConocoPhillips shall meet the 40 CFR 60, Subpart A & J requirements by operating the flare such that it only receives process upset gas, fuel gas that is released to the flare as a result of relief valve leakage, or other emergency malfunctions (as defined in 40 CFR 60, Subpart J) (ConocoPhillips Consent Decree Paragraph 156, ARM 17.8.749 and 40 CFR 60, Subpart J). After modification of the Jupiter Flare, ConocoPhillips shall meet the 40 CFR 60, Subparts A & Ja requirements (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

D. Testing Requirements – NSPS, NESHAP, and MACT

1. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.

2. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

3. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart J, Standards of Performance for Petroleum Refineries.

4. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.

5. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart Ka, Standards of Performance for Storage Vessels for Petroleum Liquids. This shall apply to all petroleum liquid storage vessels for which construction, reconstruction or modification commenced after May 18, 1978, and prior to July 23, 1984 (for requirements not overridden by 40 CFR 63, Subpart CC). These requirements shall be as specified in 40 CFR 60.110a through 60.115a.

6. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels. This shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984 (for requirements not overridden by 40 CFR 63, Subpart CC).

7. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries.

8. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

9. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60, Subpart QQQ, Standards of Performance for Volatile Organic Compound Emissions from Petroleum Refinery Wastewater Systems (for requirements not overridden by 40 CFR 63, Subpart CC).

10. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63, Subpart R, NESHAPs for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations).

11. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63, Subpart CC, NESHAPs from Petroleum Refineries.

12. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63, Subpart UUU, NESHAPs for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

13. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63, Subpart EEEE, NESHAPs for Organic Liquids Distribution (Non-Gasoline); and

E. Emission Testing and Monitoring

1. ConocoPhillips shall test boilers #B-5 and #B-6 for NO_X and CO, both pollutants concurrently, and demonstrate compliance with the NO_X and CO emission limits contained in Sections II.C.1.f.vi and vii. The compliance source testing shall be conducted on an every 5-year basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and 17.8.749).

2. ConocoPhillips shall conduct compliance source tests on the Jupiter SRU Main stack for PM_{10} and NO_X to determine compliance with the applicable emission standards in Section II.C.1.a in 1998, 2002, within 180 days of startup of the New Crude and Vacuum Units, and every 5 years thereafter.

3. The bulk loading rack VCU shall be tested for total organic compounds, and compliance demonstrated with the emission limitation contained in Section II.C.3.a every 5 years. ConocoPhillips shall conduct the test methods and procedures as specified in 40 CFR 63.425, Subpart R (ARM 17.8.105 and 17.8.342).

4. After 2007, for the life of the Consent Decree, ConocoPhillips shall conduct an annual PM stack test on the FCCU stack by December 31st unless another testing schedule is approved by EPA, in order to demonstrate compliance with the PM limitations listed in Section II.C.1.d.vii. (ConocoPhillips Consent Decree, Paragraph 46 and 47, amended). After the life of the Consent Decree,

ConocoPhillips shall conduct a PM stack test annually, unless another testing schedule is approved by the Department (ARM 17.8.749).

5. ConocoPhillips shall conduct an initial source test on the New Vacuum Heater (H-2401) within 180 days of initial startup for NO_x to demonstrate compliance with the limitations contained in Sections II.C.1.e.xxxv and xxxix. Thereafter, testing shall be conducted as required by the Department (ARM 17.8.105).

6. ConocoPhillips shall conduct an initial Method 9 opacity test on the wastewater treatment thermal oxidizer within 180 days of initial start up to demonstrate compliance with the limitations contained in Section II.C.1.i.i.a and b. If any opacity is observed during this initial test, then ConocoPhillips shall conduct a source test to demonstrate compliance with Section II.C.1.i.i.b (ARM 17.8.105).

7. ConocoPhillips shall install and operate the following CEMS/continuous emission rate monitors (CERMs):

   a. <u>Jupiter SRU/ATS Stack</u>

      i. SO_2 (SO_2 State Implementation Plan (SIP), 40 CFR 60, Subpart J, and 40 CFR 60, Subpart Ja)

      ii. O_2 (40 CFR 60, Subpart J, and 40 CFR 60, Subpart Ja)

      iii. Volumetric flow rate (SO_2 SIP)

   b. <u>FCCU Stack</u>

      i. SO_2 (SO_2 SIP; ARM 17.8.749; 40 CFR 60, Subpart J; and Consent Decree Paragraph 41)

      ii. Volumetric flow rate (SO_2 SIP)

      iii. Opacity (ARM 17.8.749; 40 CFR 51, Appendix P; 40 CFR 60, Subpart J; and Consent Decree Paragraph 47)

      iv. CO (ARM 17.8.749; 40 CFR 60, Subpart J; and Consent Decree Paragraph 49, 51 & 54)

      v. O_2 (Consent Decree Paragraph 41, 49 & 50)

   c. <u>Main Boiler Stack</u>

      i. SO_2 (SO_2 SIP; Consent Decree Paragraph 71)

      ii. Volumetric flow rate (SO_2 SIP)

   d. <u>Boilers #B-5 and #B-6</u>

      i. NO_X (40 CFR 60, Subpart Db)

      ii. O_2 (ARM 17.8.749)

e. New Crude Unit Heater (H-2301)

i. NO_x (ARM 17.8.340 and 40 CFR 60, Subpart Ja)
ii. O_2 (ARM 17.8.340 and 40 CFR 60, Subpart Ja)

f. Boilers, RFG Heaters/Furnaces, and Wastewater Treatment System Thermal Oxidizer

Continuous H_2S RFG System Monitoring - Compliance with the limits of 40 CFR 60, Subpart J shall be determined by the H_2S CEMS on the fuel gas system that supplies the heaters and boilers (SO_2 SIP, and ConocoPhillips Consent Decree, Paragraph 69). Compliance with the limits listed in Sections II.C.1.e.v – vi and II.C.1.i.iii shall be determined by the H_2S CEMS on the fuel gas system that supplies the heaters and wastewater treatment system thermal oxidizer (ARM 17.8.340; 40 CFR 60, Subpart Ja; and ARM 17.8.105). Continuous refinery fuel gas monitoring system for H_2S shall meet all performance specifications, methods and procedures. H_2S concentration monitor on the fuel gas system shall meet 40 CFR 60, Appendix B, Performance Specification 7.

g. Flare(s): (Refinery Main Plant Relief Flare, and Jupiter Flare)

i. ConocoPhillips shall maintain records of the extent and duration of all periods in which the FGRS for the Refinery Main Plant Relief Flare is not operated. During such periods, ConocoPhillips shall also measure or estimate (as appropriate) all SO_2 emissions which result from gases being directed to and combusted in the flare.

ii. Flow rate metering from upset or malfunctioning process units that are directed to the flare shall use approved standards, methods, accounting procedures, and engineering data.

iii. Recordkeeping requirements (see Sections II.F.1-2)

8. Enforcement of Section II.C.1 and II.C.6 requirements, where applicable, shall be determined by utilizing data taken from CEMS and other Department-approved sampling methods. However, opacity compliance may also be determined via EPA Reference Method 9 by a certified observer or monitor.

a. The above does not relieve ConocoPhillips from meeting any applicable requirements of 40 CFR 60, Appendices A and B, or other stack testing that may be required by the Department.

b. Other stack testing may include, but is not limited to, the following air pollutants: SO_2, NO_X, ammonia (NH_3), CO, PM, PM_{10}, and VOC.

c. Reporting requirements shall be consistent with 40 CFR Part 60, or as specified by the Department.

d. SO_2 SIP CEMS shall be required to be maintained such that they are available and operating at least 90% of the source operating time during any reporting period (quarterly).

9. ConocoPhillips shall install, operate and maintain the applicable CEMS/CERMS listed in Sections II.E.7.a, b, and c. Emission monitoring shall be subject to 40 CFR 60, Subpart J, Appendix B (Performance Specifications 1, 2, 3, 4/4A/4B, and 6) and Appendix F (Quality Assurance/Quality Control) provisions.

10. ConocoPhillips shall install, operate and maintain the applicable CEMS/CERMS listed in Section II.E.7.d. Emission monitoring shall be subject to 40 CFR 60, Subpart Db; Appendix B (Performance Specifications 2, 3, 4/4A/4B, and 6). Emission monitoring shall be subject to 40 CFR 60, Appendix F or an alternate site-specific monitoring plan approved by the Department, as appropriate.

11. ConocoPhillips shall install, operate and maintain the applicable CEMS/CERMS listed in Sections II.E.7.a and e. Emission monitoring shall be subject to 40 CFR 60, Subpart Ja, Appendix B (Performance Specifications 2 and 3) and Appendix F (Quality Assurance/Quality Control) provisions.

12. ConocoPhillips shall install, operate and maintain the applicable CEMS/CERMS listed in Sections II.E.7.f. Emission monitoring shall be subject to 40 CFR 60, Appendix B (Performance Specification 7) and Appendix F (Quality Assurance/Quality Control) provisions (the cylinder gas manufacturer's procedures for certifying these standards shall be considered adequate for Appendix F purposes).

13. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, ConocoPhillips shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated. The Department shall approve such contingency plans.

14. Compliance testing and continuous monitor certification shall be as specified in 40 CFR 60, Appendices A and B. Test methods and procedures, where there is more than one option for any given pollutant, shall be worked out with the Department prior to commencement of testing.

15. ConocoPhillips shall conduct compliance testing and continuous monitor certification as specified in 40 CFR 60, Appendices A and B, within 180 days of initial start up of the affected facility.

16. Any stack testing requirements that may be required in Sections II.E.1 to E.6, and Section II.E.8 shall be conducted according to 40 CFR 60, Appendix A and ARM 17.8.105, Testing Requirements provisions.

17. ConocoPhillips shall implement a monitoring, inspection, and maintenance plan to comply with the control requirements listed in Section II.C.1.j for the New Cooling Water Tower. This monitoring program shall consist of monitoring the free chlorine content in the cooling tower water at least three times per week, recording the bleach additive usage on an ongoing basis, and performing olfactory hydrocarbon leak detection measures at least once per shift. Any exchanger leaks that are identified must be repaired in a timely manner.

18. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

19. The Department may require further testing (ARM 17.8.105).

F. Reporting

1. ConocoPhillips shall provide quarterly and/or semi-annual emission reports from all emission rate monitors. In addition to any specific NSPS or NESHAP reporting requirements, the periodic reports shall include the following:

   a. Quarterly emission reporting for SO_2 from all point source locations shall consist of 24-hour calendar-day totals per calendar month;

   b. Source or unit operating time during the reporting period;

   c. Monitoring down time, which occurred during the reporting period;

   d. A summary of excess emissions for each pollutant and averaging period identified in Section II.C; and

   e. Reasons for any emissions in excess of those specifically allowed in Section II.C. with mitigative measures utilized and corrective actions taken to prevent a recurrence of the upset situation.

   ConocoPhillips shall submit the quarterly and/or semi-annual emission reports within 30 days of the end of each reporting period.

2. ConocoPhillips shall keep the Department apprised of the status of construction, dates of performance tests, and continuous compliance status for each emission point and pollutant. Specifically, the following report and recordkeeping shall be submitted in writing:

   a. Notification of date of construction commencement, cessation of construction, restarts of construction, startups, initial emission tests, monitor certification tests, etc.

   b. Submittal for review by the Department of the emissions testing plan, results of initial compliance tests, continuous emission monitor certification tests, continuous emission monitoring and continuous emissions rate monitoring quality assurance/quality control plans, and excess emissions report within the 180-day shakedown period.

   c. Copies of emissions reports, excess emissions, and all other such items mentioned in Section II.F.2.a and b above shall be submitted to both the Billings Regional Office and the Helena office of the Department.

   d. Monitoring data shall be maintained for a minimum of 5 years at the ConocoPhillips Refinery and Jupiter sulfur recovery facilities.

   e. All data and records that are required to be maintained must be made available upon request by representatives of the EPA.

3. ConocoPhillips shall report to the Department any time in which the sour water stripper stream from the refinery is diverted away from the sulfur recovery facility. Said excess emission reports shall include the period of diversion, estimate of lost raw materials (H_2S and NH_3), and resultant pollutant emissions, including circumstances explaining the diversion of this stream. Said excess emission reports shall discuss what corrective actions will be taken to prevent recurrences of the situation and what caused the upset. These reports shall address, at a minimum, the requirements of ARM 17.8.110.

4. ConocoPhillips shall document, by month, the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No.2 H_2 Unit PSA Offgas Vent. By the 30th day of each month ConocoPhillips shall total the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No.2 H_2 Unit PSA Offgas Vent during the previous month. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

5. ConocoPhillips shall document, by month, the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No.1 H_2 Unit PSA Offgas Vent. By the 30th day of each month ConocoPhillips shall total the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No.1 H_2 Unit PSA Offgas Vent during the previous month. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

G. Additional Reporting Requirements - NSPS, NESHAP, and MACT:

1. ConocoPhillips shall keep records and furnish reports to the Department as required by 40 CFR 60, NSPS, Subpart Kb, for requirements not overridden by 40 CFR 63, Subpart CC. These reports shall include information described in 40 CFR 60.115b.

2. ConocoPhillips shall provide copies to the Department, upon the Department's request, of any records of tank testing results required by 40 CFR 60.113b and monitoring of operations required by 40 CFR 60.116b. Records will be available according to the time period requirements as described in 40 CFR 60.115b and 40 CFR 60.116b.

3. ConocoPhillips shall keep records and furnish reports to the Department as required by 40 CFR 60, Subpart QQQ, for requirements not overridden by 40 CFR 63, Subpart CC.

4. ConocoPhillips shall provide copies to the Department, upon the Department's request, of any records of testing results, monitoring operations, recordkeeping and report results as specified under 40 CFR 60, Subpart QQQ, Sections 60.693-2, 60.696, 60.697, and 60.698, for requirements not overridden by 40 CFR 63, Subpart CC.

5. Prior to the vapor from the CPIs being controlled by the wastewater system thermal oxidizer, ConocoPhillips shall monitor the exhaust vent stream from the wastewater CPI separators carbon-adsorption system (T-169 & T-170 carbon canisters) on a regular schedule according to the requirements contained in 40 CFR

60, Subpart QQQ, Section 60.695(a)(3)(ii) and 40 CFR 61 Subpart FF, Section 61.354(d). The existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored at intervals not to exceed 14.4 hours, when the wastewater treatment is operational. The time period may be revised by the Department in the event that the carbon absorption system is upgraded or physically altered.

6. ConocoPhillips shall supply the Department's Permitting and Compliance Division with the reports as required by 40 CFR 61, Subpart FF, NESHAP for Benzene Waste Operations, for requirements not overridden by 40 CFR 63, Subpart CC.

7. ConocoPhillips shall keep all records and furnish all reports to the Department as required by 40 CFR 63, Subpart R, NESHAPs for Gasoline Distribution Facilities. These reports shall include information described in 40 CFR 63.424, 63.427, and 63.428.

8. ConocoPhillips shall keep all records and furnish all reports to the Department as required by 40 CFR 63, Subpart CC, NESHAPs for Petroleum Refineries (MACT I).

9. ConocoPhillips shall keep all records and furnish all reports to the Department as required by 40 CFR 63, Subpart UUU, NESHAPs for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (MACT II).

10. ConocoPhillips shall keep all records and furnish all reports to the Department as required by 40 CFR 63, Subpart EEEE, NESHAPs for Organic Liquids Distribution (Non-Gasoline).

H. Operational Reporting Requirements

1. ConocoPhillips shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the most recent emission inventory report and sources identified in this permit.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information is required for the annual emission inventory and to verify compliance with permit limitations. The information supplied shall include the following (ARM 17.8.505):

a. Sources – ConocoPhillips

Emission Point	Source	Consumption
Refinery		
1	**Boilers** - Four (4): #B-1, #B-2, #B-5, #B-6	MMscf of gas, %H_2S, gal of fuel oil, %S
2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 20 21 28 29 35 43 48 49	**Heaters** ["22-Fuel-Gas-Heaters"]: #1 (remove within 180 days of start-up of New Crude Heater (H-2301)) #2 #4 #5 Coke Heater (H-3901) #10: No.2 HDS #11: No.2 HDS Debutanizer Reboiler #12: No.2 HDS Main Frac. Reboiler #13: Catalytic Reforming Unit #2 #14: Catalytic Reforming Unit #2 #15 #16: Saturated Gas Stabilizer Reboiler and PB Merox Disulfide Offgas #17 (remove within 180 days of start-up of New Vacuum Heater (H-2401)) #18 #19 #20 #21 #23: Catalytic Reforming Unit #2 #24(remove within 180 days of start-up of New Crude Heater (H-2301)) Recycle Hydrogen Heater (H-8401) Fractionator Feed Heater (H-8402) No. 1 H_2 Reformer Heater (H-9401) No. 2 H_2 Reformer Heater (H-9701) Crude Heater (H-2301) Vacuum Heater (H-2401)	MMscf of gas, %H_2S
22	FCCU	Tons of SO_2/yr
23	Refinery Main Plant Relief Flare	Tons of SO_2/yr
24	Storage Tanks	Tons of VOC losses/yr
25	Bulk Loading	Gallons of Gasoline and Gallons of Distillate Throughput
26	Fugitive VOC Emissions	i. The number of the following fugitive VOC emission sources in service subject to 40 CFR 60, Subparts GGG and GGGa. a. Gas valves b. Light liquid valves c. Heavy liquid valves d. Hydrogen valves e. Open-end valves f. Flanges g. Pump seals/light liquid h. Pump seals/heavy liquid i. Oil/water separators Process drains

		ii. The number of the following fugitive VOC emission sources in service not subject to 40 CFR 60, Subparts GGG and GGGa. a. Valves b. Flanges c. Pump seals d. Compressor seals e. Relief valves f. Oil/water separators

27	CPI Separator Tanks	Gallons of wastewater throughput
30	No.1 Hydrogen Plant SMR Heater (22.0 MMscfd)	MMscf of natural gas MMscf of PSA gas
31	PMA Process Heater	MMscf of natural gas
32	Saturate Gas Plant	Monitoring and Maintenance Records
41 42	No.5 HDS Charge Heater No.5 HDS Stabilizer Reboiler Heater	MMscf of gas, %H_2S
45 46	No.2 H_2 Unit PSA Offgas Vent No.1 H_2 Unit PSA Offgas Vent	Tons CO/yr
47	Temporary Natural Gas Boiler	Hours of operation and MMscf of natural gas
50	WWTF Thermal Oxidizer	Hours of operation
Jupiter		
1	Main ATS Stack a. ATS unit b. Elemental sulfur unit	Tons of Product Produced
2	Jupiter Flare – a. Ammonium sulfide unit	Tons of Product Produced

2. For reporting purposes, the equipment should be identified using the emission point numbers specified.

3. ConocoPhillips shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

I. Notification

ConocoPhillips shall provide the Department with written notification of the following dates within the specified time periods.

1. Pretest information forms must be completed and received by the Department no later than 25 working days prior to any proposed test date, according to the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

2. The Department must be notified of any proposed test date 10 working days before that date, according to the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

3. For every time the Temporary Boiler is brought onsite, ConocoPhillips shall provide written notification to the Department of the initiation of operation within 15 days. The notification will include the year of construction, and natural gas firing rate (ARM 17.8.749 and 40 CFR 60.7 for NSPS-applicable sources).

SECTION III: General Conditions

A. Inspection - The recipient shall allow the Department's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver - The permit and all the terms, conditions, and matters stated herein shall be deemed accepted if the recipient fails to appeal as indicated below.

C. Compliance with Statutes and Regulations - Nothing in this permit shall be construed as relieving the permittee of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*. (ARM 17.8.756).

D. Enforcement - Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties, or other enforcement as specified in Section 75-2-401 *et seq.*, MCA.

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

F. Permit Inspection - As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by the Department at the location of the source.

G. Construction Commencement - Construction must begin within 3 years of permit issuance and proceed with due diligence until the project is completed or the permit shall be revoked (ARM 17.8.762).

H. Permit Fees - Pursuant to Section 75-2-220, MCA, as amended by the 1991 Legislature, failure to pay the annual operation fee by the permittee may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

PERMIT ANALYSIS
ConocoPhillips Company, Billings Refinery
Permit #2619-24

I. Introduction/Process Description

A. Source Description - ConocoPhillips

The ConocoPhillips Company, Billings Refinery (ConocoPhillips) is located at 401 South 23rd Street, Billings, Montana, in the NW ¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County. The refinery property is adjacent to the City of Billings and is next to Interstate 90 and the Yellowstone River. Residential properties exist on the west side of the refinery and the United States Postal Service has an office located on the south side of the property.

The refinery has the capability to process an annual average of approximately 72,500 barrels per day of crude oil and produces a wide range of petroleum products, including propane, gasoline, kerosene/jet fuel, diesel, and petroleum coke. All previously permitted equipment, limitations, conditions, and reporting requirements stated in Permits #1719, #2565, #2669, #2619, and #2619A were included in Permit #2619-02.

Emission Point	**Source**
Refinery	
1	**Boilers** - Four (4): #B-1, #B-2, #B-5, #B-6
	Heaters ["22-Fuel-Gas-Heaters"]:
2	#1 (remove within 180 days of start-up of New Crude Heater (H-2301))
3	#2
4	#4
5	#5
6	Coke Heater (H-3901)
7	#10: No.2 HDS
8	#11: No.2 HDS Debutanizer Reboiler
9	#12: No.2 HDS Main Frac. Reboiler
10	#13: Catalytic Reforming Unit #2
11	#14: Catalytic Reforming Unit #2
12	#15
13	#16: Saturated Gas Stabilizer Reboiler and PB Merox Disulfide Offgas
14	#17 (remove within 180 days of start-up of New Vacuum Heater (H-2401))
15	#18
16	#19
17	#20
18	#21
20	#23: Catalytic Reforming Unit #2
21	#24(remove within 180 days of start-up of New Crude Heater (H-2301))
28	Recycle Hydrogen Heater (H-8401)
29	Fractionator Feed Heater (H-8402)
35	No. 1 H_2 Reformer Heater (H-9401)
43	No. 2 H_2 Reformer Heater (H-9701)
48	Crude Heater (H-2301)
49	Vacuum Heater (H-2401)

22	FCCU
23	Refinery Main Plant Relief Flare
24	Storage Tanks
25	Bulk Loading
26	Fugitive VOC Emissions
27	CPI Separator Tanks
30	No.1 Hydrogen Plant SMR Heater (H-9401) (22.0 MMscfd)
31	PMA Process Heater
32	Saturate Gas Plant
41 42	No.5 HDS Charge Heater No.5 HDS Stabilizer Reboiler Heater
45 46	No.2 H_2 Unit PSA Offgas Vent No.1 H_2 Unit PSA Offgas Vent
47	Temporary Natural Gas Boiler
50	Wastewater Treatment System Thermal Oxidizer

B. Source Description – Jupiter Sulphur, LLC

Jupiter Sulphur, LLC (Jupiter) operates a sulfur recovery facility, within the petroleum refinery area described above, at 2201 7th Avenue South, Billings, Montana. The facility is operated as a joint venture, of which ConocoPhillips is a partner. ConocoPhillips is responsible for maintaining air permit compliance at Jupiter's sulfur recovery facility.

Jupiter's total sulfur recovery capacity is 295 Long Tons per Day (LT/D) of sulfur. The Jupiter facility consists of three primary units: the Ammonium Thiosulfate (ATS) Plant, the Ammonium Sulfide Unit (ASD), and the Claus Sulfur and Tail Gas Treating Units (TGTUs).

Jupiter's new Claus Sulfur and TGTUs shall have three parallel single-stage high-efficiency gas filters for final particulate and sulfur dioxide (SO_2) control. All emissions from these three primary processes are vented to Jupiter's main stack.

Emission Point	**Source**
1	Main ATS Stack a. ATS unit b. Elemental sulfur unit
2	Jupiter Flare – a. Ammonium sulfide unit

C. Permit History

On October 29, 1982, Conoco Inc. (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 5,000-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 2,000-barrel desalter wastewater break tanks equipped with external floating roofs and double-rim seals. The new tanks were to augment the refinery's ability to control fugitive Volatile Organic Compounds (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 to 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 plant, 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.

Conoco was also permitted to construct a sulfur recovery facility (SRU)/ATS to be operated by Kerley Enterprises. This facility is operated in conjunction with the new installations and modifications at the Conoco Refinery. This facility was permitted with the capability of utilizing 109.9 LT/D of equivalent sulfur obtained from the Conoco Refinery for the manufacture of elemental sulfur and sulfur-containing fertilizer solutions (i.e., ATS).

On December 4, 1991, Conoco was issued **Permit #2619A** for the construction of a 1,000-barrel hydrocarbon storage tank (T-162). The new tank stores recovered hydrocarbon product from the contaminated groundwater aquifer beneath the Conoco Refinery. Over the years, surface discharges at the refinery contaminated the groundwater with oily hydrocarbon products. The purpose of this project was 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 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-MMscf-per-day hydrogen plant and to replace their existing American Petroleum Institute (API) separator system with a corrugated plate interceptor (CPI) separator system. This permit was an alteration to Conoco's existing Permit #2619 and included all previously permitted equipment, limitations, conditions, and reporting requirements stated in Permits #1719, #2565, #2669, #2619, and #2619A.

The natural gas feedstock to the new hydrogen plant produces 99.9% pure hydrogen. This hydrogen and hydrogen from the existing catalytic reformers is routed to the refinery hydrotreaters to reduce fuel product sulfur content. The Hydrogen sulfide (H_2S) produced is routed to the Jupiter SRU/ATS, operated by Kerley Enterprises, which produces sulfur and fertilizer products.

The two new CPI separator tanks with carbon canister total VOC controls were constructed to comply with 40 Code of Federal Regulations (CFR) 60, Subpart QQQ, and 40 CFR 61, Subpart FF regulations. The CPI separators were vented to two carbon canisters in series. Each carbon canister was designed and operated to reduce VOC emissions by 95% or greater, with no detectable emissions. This CPI separator system replaced the existing API separator system.

As per a letter received by the Department of Environmental Quality (Department), on December 22, 1992, ownership of the Kerley Enterprises facility was transferred 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 Unit (FCCU) feed gas oils, which allows the FCCU to produce low-sulfur gasoline. This low-sulfur gasoline was required by January 1, 1995, to satisfy Environmental Protection Agency's (EPA) gasoline sulfur provisions of the Federal 1990 Clean Air Act Amendments. Hydrogen requirements are met by the installation of a hydrogen plant, and sulfur recovery capacity was provided by installing additional elemental liquid sulfur production facilities at the Jupiter Sulphur, Inc. plant adjacent to the refinery.

The Gas Oil Hydrodesulfurizer (GOHDS) was designed to meet the primary objective of removing sulfur from the FCCU 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 H_2S removal and recycled.

The new project did not increase refinery capacity. The project did not constitute a major modification for purposes of the New Source Review - Prevention of Significant Deterioration (NSR-PSD) program since net emissions did not increase in significant amounts as defined by the Administrative Rules of Montana (ARM) 17.8.801(20)(a).

The additional fugitive VOC emissions from this project were calculated by totaling the fugitive sources on the process units. These sources included flanges, valves, relief valves, process drains, compressor seal degassing vents and accumulator vents and open-ended lines. The fugitive source tabulation was then used with actual refinery emission factors obtained from the Conoco Refinery in Ponca City, Oklahoma. Furthermore, it was intended that each non-control valve in VOC service would be repacked with graphite packing to Conoco standards before installation. All control valves for the GOHDS project would 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.

The Jupiter Sulphur, Inc. Recovery Facility consists of three primary units: the existing ATS Plant, the existing ATS Unit and the new Claus Sulfur and TGTU. The addition of the new units increased the total sulfur recovery capacity of the facility from 110 to 170 LT/D of sulfur.

The existing ATS plant consisted of a thermal Claus reaction-type boiler. The exit gas from this Claus boiler is incinerated in the ATS Unit. The SO_2 from the incinerator is absorbed and converted to ammonium bisulfite (ABS). The ABS is then used to absorb and react with H_2S 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 ASD consists of an absorption column, which absorbs the sulfur as H_2S in the acid gas feed and reacts with NH_3 and water. When the new Claus Sulfur Unit was added, the Sulfur Recovery Facility was modified to incinerate any off gas from this unit in the TGTU and

ATS Plant. This eliminates off-gas flow to, and emissions from, the flare. Up to 110 LT/D of sulfur can be processed by the ASD to produce ammonium sulfide solution.

The proposed Claus Sulfur Unit consisted 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, SO_2 from the incinerator was absorbed and converted to ABS. This ABS is then transferred to the ATS Unit for conversion to ATS. Up to 110 LT/D of sulfur can be processed by the new 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 combines "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 Inc.'s sour gases at all times. A maximum of 170 LT/D of sulfur is recovered and each of the three units has a capacity of 110 LT/D. If any one 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-flushed 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 involved the recommissioning of an out-of-service compressor and associated equipment components having fugitive VOC emissions. The project also involved the installation of new equipment components having fugitive VOC emissions. The recommissioned compressor was originally installed in 1948. The compressor underwent some minor refurbishing, but did not trigger "reconstruction" as defined in 40 CFR 60.15.

The purpose of the C-23 compressor station project was 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) was lowered.

On February 2, 1994, Conoco was issued **Permit #2619-05** to construct and operate a butane defluorinator within the alkylation unit at the refinery. Installation of an alumina (Al_2O_3) bed defluorinator system was to remove residual hydrofluoric acid (HF) and organic fluorides from the butane stream produced by the Alkylation Unit. This reduced the fluorine level of the butane from ~ 500 parts per million by weight (ppmw) to ~ 1 ppmw, which allows the butane to be recycled back to the refinery's Butamer Unit for conversion into isobutane. Refer to the permit application for a more thorough description of the process and proposed changes.

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 operation of the refinery's gasoline blending to restructure butane blending and lower the vapor pressure

of the gasoline pool; (3) minimized butane sales; (4) minimized butane burning as refinery fuel gas; and (5) economized 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 to become a supplier of PMA for the region.

Installation of a 9.5-million British thermal units per hour (MMBtu/hr) natural gas-fired process heater to heat an oil heat transfer fluid supplies heat to bring the asphalt base to 400°F. This allows a polymer material to be mixed with it to produce PMA. A hot oil transfer pump was installed to circulate hot oil through the system. A heat exchanger (X-364) from the shutdown Propane De-asphalting (PDA) Unit was moved and installed to aid in the heating of the asphalt base. Two existing 5,000-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 lines, a new asphalt transfer pump, and a new 5,000-bbl PMA storage tank (to replace the demolished T-50) were installed to keep the PMA separated from other asphalt products.

This permit alteration also addressed the items submitted in a letter dated November 23, 1993, for supplemental information and a request for permit clarification for Conoco's Permit #2619-03. This permit clarifies all these items, as appropriate, including the issues relating to the redesign of the SRU stack and the addition of heated air to the stack. Reference Section VI, Air Quality Impacts.

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. The 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 existing equipment was located next to the new depropanizer. The old depropanizer was retained in place and may be used in the future in non- HF service.

The decommissioned PDA Unit evaporator tower (W-3) was converted to a water wash tower to remove entrained amine from the Alky PB (Propane/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 was an increase in fugitive VOC emissions, as well as additional emission of fluorides due to the installation of the new depropanizer piping and valves.

The changes made by this project were not subject to NSR-PSD review since the sum of the emission rate increases were 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 Standards of Performance for New Stationary Sources (NSPS), Subpart QQQ (Wastewater Treatment System VOC Emissions in Petroleum Refineries) and National Emission Standards for Hazardous Air Pollutants (NESHAP), Subpart FF

(Benzene Waste Operations). These drains were 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 SO_2 emissions 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 H-8402) into one SO_2 point source within the Refinery. The project is referred to as the Existing Heater Optimization Project.

The 19 process heaters being discussed in this application 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-Heater" source. Also included in this discussion are the Coker heater (H-3901) and the GOHDS heaters (H-8401 and H-8402).

The existing 19 heaters have a "bubbled" SO_2 permit emission limit of 30.0 tons per year (TPY) (164 lb/day) and a limitation of fuel gas H_2S content of 160 parts per million by volume (ppmv) (0.1 grains per dry standard cubic foot (gr/dscf)). With both these limitations intact, all of these heaters cannot simultaneously operate at their maximum design firing rates. This can cause un-optimized operation of the Refinery during unfavorable climatical conditions or during peak heater demand periods.

To allow all 19 heaters to simultaneously operate at their maximum firing rates, the allowable short term SO_2 emission limit for the "bubbled" 19 heaters must be increased. The (19) Refinery Fuel Gas Heaters/Furnaces lb/day SO_2 emission limitation was based on British thermal units per hour (MMBtu/hr) from the emission inventory database (AFS), and higher fuel heat value (1,015 British thermal units per standard cubic foot (Btu/scf)) from the 1990 Base-Year Carbon Monoxide Emission Inventory. By using these parameters, the daily "bubble" SO_2 permit limit can be raised to 386 lb/day, as was indicated in the Preliminary Determination. Conoco requested the daily limit be increased to 612 lb/day, which is equivalent to the rate used in the Billings SO_2 State Implementation Plan (SIP) modeling (111.7 TPY). The annual "bubble" SO_2 limit of 30.0 TPY was maintained.

The Department received comments from Conoco, in which Conoco contends that the maximum heat input (MMBtu/hr) from the AFS does 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. This total maximum firing rate was identified by Conoco during the permit review of the Coker permit (Permit #2619). The maximum heat input of 785.5 MMBtu/hr and the fuel heat of 958 Btu/scf are used to calculate a new daily "bubble" SO_2 permit limit of 529.17 lb/day.

The change in air emissions of other criteria pollutants (carbon monoxide (CO), nitrogen oxide (NO_X), particulate matter (PM), and VOC) associated with this project are zero, since the Potentials to Emit (PTE) were not changed. With the current 164-lb/day SO_2 limit, simultaneous maximum firing of these heaters can be accomplished if the fuel gas H_2S content stays below 49.75 ppmv. Conoco's amine systems produce fuel gas averaging (on an annual basis) of about 25 ppmv H_2S content or less (see 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 current amine system can 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 were 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 was not affected as well.
Even though Conoco's past annual average fuel gas H_2S content was below 37.8 ppmv, there was still potential to run into operational limitations in peak fuel gas demand periods. The amine systems may not be able to keep the fuel gas H_2S under 49.75 ppmv, rendering the refinery to operate at un-optimized 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 PTE, the project is not subject to 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 SIP for the Billings-Laurel area (see the Billings/Laurel SO_2 SIP Compliance Demonstration Report dated November 15, 1994). The "19-Heater source" was modeled using an SO_2 emission rate equivalent to 111.7 TPY to determine its 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 its operation. Therefore, an increase in the permit limit from 164 lb/day to 612 lb/day of SO_2 did not result in any violations of SO_2 NAAQS or Montana standards; however, the daily emission limit set based on the NSPS limit of 0.1 grains per dry standard cubic foot (gr/dscf) (160 ppmv H_2S) is more restrictive than the SIP limit. The daily emission limit, based on NSPS, is 529.17 lb/day for the existing 19 heaters/furnaces.

With the change of a daily SO_2 permit limit for the "19-Heater" source, Conoco also 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-Heaters" 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 allows Conoco more operational flexibility with regard to heater firing rates and heater optimization. The Coker heater still has an hourly NO_X emission limit to prevent any significant impacts. This permit alteration does not allow an increase in the annual NO_X emissions. Permit #2619-09 replaced Permit #2619-08.

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 installed 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 were collected from the trucks during loading, then routed to an enclosed

flare, where combustion occurs. The project results in overall reductions in the amount of actual emissions of VOCs (94.8 TPY), with a slight increase in CO (2.1 TPY) and NO_X (0.8 TPY) emissions. The actual 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.
In addition, Conoco requested an administrative change be made to Section II.F.5, which brought 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 tank VCU is defined as an incinerator under MCA 75-2-215, a determination that the emissions from the VCU constitutes a negligible risk to public health is required prior to the issuance of a permit to the facility. Conoco and the Department identified the following HAPs 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 HAPs is contained in the January 1992 CAPCOA Risk Assessment Guidelines. The model performed by Conoco for the HAPs identified above, demonstrate compliance with the negligible risk requirement. Permit #2619-10 replaced Permit #2619-09.

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 #2161-10 required the production of SO_2 from the sulfur containing compounds in the PB Merox Unit off-gas stream to be calculated and counted against the current SO_2 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 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). SO_2 produced from the continuous incineration of this stream has been calculated at approximately 1 TPY. 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 proposed 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, is used to calculate the production of SO_2. After a year of sampling time and with the approval of the Department, Conoco may propose 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 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 approved the request and the correction was made, but 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 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 PTE 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 FCCU. 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 (lbs/hr) for each of the SRU Flare and SRU/ATS Main Stack to a 25-lbs/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 exceed 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 Offgas 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 Offgas 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 FCCU became subject to the SO_2 portions of Standards of Performance for New Stationary Sources (NSPS), 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 NSPS 40 CFR 60, Subparts A and J (as requested September 28, 2004)
- FCCU – to clarify that the FCCU 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)

- FCCU - to clarify that the FCCU 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 FCCU shall not apply during periods of hydrotreater outages (requested February 1, 2006)

- 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 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 FCCU is subject to a PM emission limit of 1 lb per 1,000 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 FCCU 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** replaced MAQP #2619-22.

D. Current Permit Action

On August 21, 2008, the Department received a complete NSR-PSD permit application from ConocoPhillips. ConocoPhillips is proposing 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. The NCVU project will enable 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 will require 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 are 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 will need 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} have now been 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** replaces MAQP #2619-23.

E. Response to Public Comments

Person/Group Commenting	Permit Reference	Comment	Department Response
ConocoPhillips	Pg 2. II.A.1.d.ii. and iv	The Jupiter Claus unit and Jupiter Flare will become subject to NSPS Subpart Ja (as currently promulgated) when modified for the NCVU project. Once subject to NSPS Subpart Ja they will no longer be subject to NSPS Subpart J. Hence, ConocoPhillips suggests adding a parenthetical clarification to each of these conditions: (until it becomes subject to NSPS Subpart Ja)	The Department has made the requested changes.
ConocoPhillips	Pg 2. II.A.1.d.iii and Pg 7. II.B.1	These conditions reference the Main Plant Relief Flare and its spare. The spare flare no longer exists at the refinery. Accordingly, ConocoPhillips requests the reference to the spare flare be removed from these conditions.	The Department has made the requested change.
ConocoPhillips	Pg 4. II.A.1.i.	This condition lists the units subject to NSPS Subpart GGG. The old Crude Vacuum Unit will be removed from service upon start-up of the NCVU start up and will no longer be subject to NSPS Subpart GGG. Hence, ConocoPhillips suggests adding a parenthetical clarification after Crude Vacuum Unit: (until no longer in service)	The Department has made the requested change.
ConocoPhillips	Pg. 5. II.A.1.j	ConocoPhillips suggest editing the text to make it clear that NSPS Subpart GGGa applies to all of the fugitive VOC emitting components added in the NCVU project, which will include the off-gas compressor, by deleting <u>off-gas</u>	The Department has modified the language to include all of the fugitive VOC emitting components added in the NCVU project (including the off-gas compressor) as subject to Subpart GGGa.

		compressor from the condition.	
ConocoPhillips	Pg 5. II.A.1.k	Please list the No. 1 H_2 Unit at its proposed new capacity of 22 MMscfd rather than its present capacity of 20 MMscfd.	The Department has made the requested change.
ConocoPhillips	Pg 8. II.B.10	ConocoPhillips did not adequately describe in the permit application that the vapor vent from the CPI separators will be re-routed to the new wastewater treatment thermal oxidizer, rendering the carbon canister system no longer necessary in the future. Please revise this condition to reflect this future change. Suggestion: ConocoPhillips shall operate and maintain two CPI separator tanks with either carbon canister total VOC controls or a closed vent system routed to the wastewater treatment thermal oxidizer to comply with 40 CFR 60, Subpart QQQ, and 40 CFR 61, Subpart FF regulations. The CPI separators will be vented to either two carbon canisters in series, or the wastewater treatment thermal oxidizer, designed and operated to reduce VOC emissions by 95%, or greater, with no detectable emissions.	The Department has made the requested change.
ConocoPhillips	Pg 12. II.B.17	This condition, as proposed, requires ConocoPhillips to install, operate, and maintain a thermal oxidizer on the new wastewater treatment facility according to manufacturer's specifications. Because the manufacturer selection has not been selected at this time, ConocoPhillips and the MtDEQ are not able to review the manufacturer's specifications. Thus, the full implications of this permit condition can not be evaluated. To fully define the requirements of this condition ConocoPhillips requests that according to manufacturer's specifications be replaced with the language of ARM 17.8.752: ...to provide the maximum air pollution control for which it was designed.	The Department has made the requested change.

ConocoPhillips	Pg 13. II.C.1.b.ii	The regulatory reference of this condition should also include NSPS Subpart Ja, as the Jupiter flare will become subject to NSPS Subpart Ja (as currently promulgated), but no longer NSPS Subpart J, when it is modified for the NCVU project.	The Department has made the requested change.
ConocoPhillips	Pg 13. II.C.1.d.i.	To match the permit application (Page 8 of 52 of the application forms) the SO_2 annual emission limitation for the FCC unit stack should be 48.86 TPY.	This permit limit change was inadvertently left out of the preliminary determination. The Department has made the requested change.
ConocoPhillips	Pg 14. II.C.1.e.ii.	For clarity, ConocoPhillips requests a list of the heaters in the emission cap be included in this permit condition. This list, which puts 22 heaters within the cap after start-up of the NCVU, includes: H-1 (remove after NCVU Start-up) H-2 H-4 H-5 H-10 H-11 H-12 H-13 H-14 H-15 H-16 H-17 (remove after NCVU Start-up) H-18 H-19 H-20 H-21 H-23 H-24 (remove after NCVU Start-up) H-2301 (after start-up of NCVU) H-2402 (after start-up of NCVU) H-3901 H-8401 H-8402 H-9401 (after start-up of NCVU) H-9701 (after start-up of NCVU)	The Department has made the requested change.
ConocoPhillips	Pg 15. II.C.1.e.v. and vi	These conditions limit the H_2S content of the fuel fired in the two new heaters. The H_2S content of the fuel fired in the two new heaters is not dependent on the startup or shutdown of the heaters themselves, but rather is dependent on the startup and shutdown of the refinery fuel gas treating system. ConocoPhillips requests these conditions be modified to clarify that the 162 ppmv H_2S in fuel gas	The Department has made the requested change.

		limits apply during startup and shutdown of the refinery fuel gas treating system rather than the individual heaters.	
ConocoPhillips	Pg 19. II.C.1.i.	ConocoPhillips requests that the stack concentration limitations for NO_x and CO for the wastewater treatment thermal oxidizer be clarified to include a specific measurement period. The PSD permit analysis for this unit was based on an annual emission rate. Therefore, it would be appropriate to state the concentration limits on an annual basis.	The Department has made the requested change.
ConocoPhillips	Pg 22. II.C.7.i.	This condition for the Jupiter Flare should also reference NSPS Subpart Ja, as the Jupiter flare will become subject to NSPS Subpart Ja (as currently promulgated), but no longer Subpart J, when it is modified for the NCVU project.	The Department has made the requested change.
ConocoPhillips	Pg 24. II.E.5	This condition should reference conditions II.C.1.i.i.a. and b. and II.C.1.i.i.b., rather than II.C.1.I.i.a. and b. and II.C.1.I.i.a.	The Department has made the requested change.
ConocoPhillips	Pg 24. II.E.6.e	This condition should list only the new Crude Unit Heater (H-2301). The new Crude Vacuum Unit heater (H-2401) firing rate will be less than 100 MMBTU/hr. Under NSPS Subpart Ja heaters of less than 100 MMBTU/hr size are not required to install CEM systems for NO_x and/or O_2. ConocoPhillips understands the Department will add a performance testing requirement for the new Crude Vacuum Unit heater (H-2401) in the permit.	The Department has made the requested change. An initial stack test will be required for the New Vacuum Heater.
ConocoPhillips	Pg 28. II.G.5	Please refer to Comment 5 above. Once the CPI carbon canisters are no longer in service this condition will not be necessary. ConocoPhillips suggests prefacing the condition with: Prior to the vapor from the CPIs being controlled by the wastewater system thermal oxidizer, ConocoPhillips shall monitor….	The Department has made the requested change.
ConocoPhillips	Pg 29. II.H.a. Table: Sources - ConocoPhillips	Heaters H-9401 and H-9701, EPNs 35 and 43, respectively, should be moved within the table to the "22 Fuel Gas Heaters" section.	The Department has made the requested changes.

		The Fugitive VOC emission category in the table should also reference 40 CFR Subpart GGGa The wastewater treatment thermal oxidizer, EPN 50, is not listed in the table. ConocoPhillips believes is should be, and suggests annual hours of operation should be reported.	
ConocoPhillips	Permit Analysis: Pg. 1 I.A. Source Description - ConocoPhillips	To avoid the possible misunderstanding that a facility throughput limitation has been established in this permitting action, ConocoPhillips requests the first line in the second paragraph be revised to: The refinery has the capability to process an annual average of approximately 72,000 barrels per day of crude oil ….. EPN 50, the wastewater treatment thermal oxidizer, should be added to the table in this section.	The Department has made the requested clarifications.
ConocoPhillips	Permit Analysis: Pg. 18 II.C.8d.d	Like comment number 2 for the proposed permit conditions ConocoPhillips requests the reference to the spare flare be removed.	The Department has made the requested change.
ConocoPhillips	Permit Analysis: Pg. 19 II.C.8.j	ConocoPhillips suggest editing the text to make it clear that GGGa applies to all of the fugitive VOC emitting components added in the NCVU project, which will include the off-gas compressor, by deleting <u>off-gas compressor</u> from the condition.	The Department has modified the language to include all of the fugitive VOC emitting components added in the NCVU project (including the off-gas compressor) as subject to Subpart GGGa.
ConocoPhillips	Permit Analysis: Pg. 24 II.G.2.	It is not technically correct to list the Total Project Net emissions for CO, VOC, H_2S, and Lead because the total project emissions increases for these pollutants was each less than the respective PSD significance level. Also, the typographical error for Contemporaneous Emission Changes for NO_x should be corrected from 29.22 to 29.23 TPY.	The Department has made the requested changes.
ConocoPhillips	Permit Analysis: Pg. 38 III. Claus SRU, 2	In the third paragraph of this section please correct (on a rolling <u>12 hour</u> average) to (on a rolling <u>365-day)</u> average.	The Department has made the requested change.

ConocoPhillips	Permit Analysis: Pg 49, third Paragraph III. 6.d	A mention of the applicability of Subpart GGGa to the project's new fugitive emission components should be included in this discussion.	The Department has made the requested change.
ConocoPhillips	Permit Analysis: Pg 50, IV. Emission Inventory Table	For the FCC, (EPN 22) please include double dash marks in the VOC column entry to indicate there are negligible VOC emissions from the FCC unit.	The Department has made the requested change.
ConocoPhillips	Permit Analysis: Pg 52, VI. Ambient Air Impact Analysis	Please revise Environ to read ConocoPhillips throughout this section, or better explain the relationship between Environ and ConocoPhillips in the introduction paragraph.	The Department has made the requested change.
ConocoPhillips	Permit Analysis: Class II Analysis	The correct number for the Great Falls National Weather Service Station is 24143.	The Department has made the requested change.
ConocoPhillips	Permit Analysis: Pg 59, VI. Ambient Air Impact Analysis	In Table VI-4, the Delta E, Plume (plume perceptibility parameter) value for the Level I Input Parameter "Sky" should be 0.103 rather than the listed value of 0.106 to match the modeling results provided by ConocoPhillips with the permit application	The Department has made the requested change.
ConocoPhillips	Permit Analysis: Pg 61, VI. Ambient Air Impact Analysis	Table VI-6 appears to include some values from the modeling report from the June 2008 permit application. Please replace the table with the table provided electronically by ConocoPhillips to the Department on October 3. For clarity, please also include the footnote below to Table VI-6: Stepping Stone Lake and Twin Island Lake are located within the Absaroka Beartooth Wilderness Area, which is a Class II area. Although these lakes are not part of a Class I area, NO_2, SO_2 and PM_{10} concentrations are presented for informational purposes only.	The Department has made the requested change.
ConocoPhillips		The NCVU project permit application states the feed capacity of the Jupiter	The Department has made the requested clarification.

		Sulfur Plant will need to be increased to approximately 235 long tons sulfur per day (LTSD) to accommodate the expected sulfur load from the NCVU project. The application describes that this increase will be provided by either an upgrade to the existing equipment or the addition of a new SRU train. Addition of a new SRU train has since been selected as the preferred option. The new SRU train will provide an approximate sulfur processing capacity of 295 LTSD, affording about 60 LTSPD redundant sulfur processing capacity to the plant. Should future refinery sulfur processing needs increase above 235 LTSD, and up to 295 LTPD, the Jupiter Plant will be able to operate within the emission limitations established in the draft permit.	
EPA*		The FCCU stack $S0_2$ emissions limit established on page 13 of permit is 328.8 1bs/hr, rolling 24-hour average; 3.945 ton/day; 1,440 TPY. This limit corresponds with the hourly emission rates used for this Unit in the final Federal Implementation Plan (FIP) issued by EPA on April 21, 2008 for $S0_2$ National Ambient Air Quality Standards (NAAQS) compliance in the Billings area. This limit also corresponds to the existing FCCU and Catalytic reforming Units 1 & 2 $S0_2$ emission cap of 1,440 tons per year in the application (see page 6 of 52; Emissions Unit specific and Plantwide Emissions Summary - ConocoPhillips application of August 2008). However, on October 10, 2008, MDEQ alerted EPA by e-mail that this limit should be 48.86 tons per year based on the Unit's PTE listed in the modeling file and not 1440 tons per year as stated in the current preliminary determination. Subsequent discussions with MDEQ revealed that the 48.86 tons per year is based on a previous requirement for the Unit and that the higher limit was inadvertently included in the permit. MDEQ needs to provide a detailed	Under the ConocoPhillips Consent Decree, SO_2 emissions from the FCCU are limited to 25 ppmv, corrected to 0% O_2, on a rolling 365-day basis; this limit equates to approximately 48.86 TPY or less. ConocoPhillips currently meets this Consent Decree limit by hydrotreating the FCCU feed and utilizing a catalyst additive in the FCCU. Even with the proposed changes to the FCCU under the NCVU project, ConocoPhillips must continue to meet this consent decree limit and does not anticipate any problems in meeting this limit. In this permitting action, ConocoPhillips requested a reduced permit limitation, in TPY, for the FCCU in order to limit its potential to emit. The Department agreed that this permit limitation was reasonable and could be met. Therefore, the requested reduction in the annual SO_2 emissions limitation for the FCCU is included in this permit in order to limit the unit's potential to emit. This revised limit matches the

		analysis of the steps ConocoPhillips is taking or proposes to take to comply with this revised limit in its permit and why the higher limit should not be applicable.	potential to emit utilized in ConocoPhillips' modeling files for this project. ConocoPhillips did not request a change to the rolling 24-hour average or ton/day permit limitations since a reduced potential to emit on a short-term basis is not necessary for this permit action and the higher short term limits allow ConocoPhillips operational flexibility.
EPA*		ConocoPhillips concludes in its application (see page II-11; Project Information - ConocoPhillips application of August 2008), that "as a result of the NCVU project, the FCCU feed rates and actual emissions from the FCCU stack are expected to increase." It is also clear from both the application as well as MDEQ's permit analysis that the FCCU will undergo significant physical reconfiguration with the addition of new components. This will include piping reconfiguration, addition of a new parallel 600 psig waste heat steam generator, a new 600 psig steam drum and replacement of a portion of the main fractionator, all of which will ultimately result in increased capacity and increased actual emissions. Unfortunately, ConocoPhillips did not identify the actual increased emissions anywhere in the application but just stated the Unit's $S0_2$ emission is 48.86 tons per year (see page 8 of 52 -ConocoPhillips application) without any explanation or the Unit emissions' analysis. Based on these facts, the discussion of the Unit's PTE above, and the fact the changes to the FCCU constitutes physical changes, EPA strongly believes that FCCU stack needs to be analyzed for BACT unless MDEQ can provide a satisfactory justification in its permit analysis why BACT analysis is unwarranted.	ARM 17.8.819(3) requires the application of BACT for each pollutant that would be a significant net emissions increase at the source. Under the NCVU project, ConocoPhillips proposes a significant net emissions increase in NO_x, SO_2, and PM/PM_{10} at the Billings Refinery. This BACT requirement applies to each proposed emission unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit. In accordance with ARM 17.8.801(20), a physical change or change in the method operation shall not include, "an increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR subpart I or section 51.166." Since the increased production rate of the FCCU is not prohibited under any federally enforceable permit condition, the Department does not consider the proposed changes to the FCCU to be a physical change or change in the method of operation. Additionally, under the definition of a FCCU as specified in 40 CFR 60.101, the fractionator and slurry oil heat exchangers are not

			considered part of the FCCU. Therefore, the changes that are being proposed for the NCVU project are not part of an 'affected source'. Therefore, the Department does not believe a BACT analysis is required for the FCCU.
EPA*		New Source Performance Standard (NSPS) Subpart Ja provisions apply to the following facilities in petroleum refineries: FCCUs, delayed coking units, fuel gas combustion devices, including flares and process heaters, and sulfur recovery plants which commence construction, modification or reconstruction after May 14,2007. For flares, the provisions of this Subpart apply to flares which commence construction, modification or reconstruction after June 24, 2008 (see 40 CFR § 60.100a (a) & (b) (a)). EPA notes that MDEQ's preliminary determination cites NSPS Subpart J and in some instances duplicates the authority as both Subpart J and Ja as the basis for the permit Conditions that cover the operations of these modified units. Such duplication lends to confusion as though there are two separate units, one of which is being modified and the other is not. MDEQ needs to revise every Condition that covers a modified unit that is currently subject to Subpart J to reflect Subpart Ja provisions and appropriate citation.	The Department has added language in the permit to clarify when Subpart J applies and when Subpart Ja applies. Because many units are subject to Subpart J until such time the unit is modified and becomes subject to Subpart Ja, duplicate references are necessary. The Department intends to delete these duplicate references, through an administrative amendment, at such time the units are modified and become subject to Subpart Ja.
EPA*		Because $S0_2$ emissions increases, due to upset conditions or temporary discontinuance of the SRU will be directed to the refinery flare gas recovery system (FGRS), and ultimately to refinery flares in emergency situation, it is conceivable that the refinery main flare and/or main flare gas recovery system will need to be modified to handle the increased flow rates that will result because of the increased capacity of the SRU. Such modification to accommodate increased flow rate would constitute modification as defined in NSPS Subpart Ja. It will	As discussed in ConocoPhillips' permit application, this project will include the addition of pressure relief vents (PRVs) from new equipment to the existing collection header for the Refinery Flare Gas Recovery Unit (FGRU). The FGRU is considered part of the fuel gas system and is upstream of the Refinery Main Flare. The FGRU is used to capture gases from process equipment, compress those gases, and direct them to the refinery's fuel gas treating system for treatment and use in refinery fuel gas combustion devices as

		also require a BACT analysis for the flare. MDEQ should provide an explanation in its permit analysis for why the refinery main flare and/or the gas recovery system will not need to be modified for increased flow rates.	fuel gas. The PRVs provide overpressure protection for equipment and do not release gases to the FGRU under normal operating conditions. As such, the PRV connections will not increase flow to the FGRU under normal operating conditions, and thus will not increase flow or flow capacity of the Main Flare. Under 40 CFR 60, Subpart Ja, as currently written, a flare is considered modified if any new piping from a refinery process unit or fuel gas system is physically connected to the flare or if the flare is physically altered to increase flow capacity after June 24, 2008. This definition has been stayed and is currently undergoing a regulatory review. Assuming the flare provisions as currently written apply, since no new piping from a refinery process unit will be connected to the flare and since the flare has not been proposed to be physically altered in order to increase flow capacity, the Department has determined that 40 CFR 60, Subpart Ja requirements have not been triggered, nor is a BACT analysis required for the refinery plant main flare. Should ConocoPhillips propose to modify the flare in the future, BACT requirements and Subpart Ja provisions will be triggered.

* These comments were received after the official public comment period ended on October 24, 2008. On October 22, 2008, EPA requested an extension of the public comment period. Since extensions of 30-day public comment periods are not allowed under ARM 17.8.759, the Department was not able to grant EPA's request. However, the Department did agree, as a courtesy, to respond to any comments submitted by EPA prior to the issuance of the Department Decision on November 3, 2008. The comments referenced above were received by the Department on October 31, 2008.

F. Additional Information

Additional information, such as applicable rules and regulations, BACT/Reasonably Available Control Technology (RACT) determinations, air quality impacts, and environmental assessments, is included in the analysis associated with each change to the permit.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the ARM and are available, upon request, from the Department. Upon request, the Department will provide references for locations of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Subchapter 1 - General Provisions, including, but not limited to:

1. ARM 17.8.101 Definitions. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment, including instruments and sensing devices, and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the Department. ConocoPhillips shall also comply with monitoring and testing requirements of this permit.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., Montana Code Annotated (MCA).

   ConocoPhillips shall comply with all requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means which, without resulting in reduction in the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner that a public nuisance is created.

B. ARM 17.8, Subchapter 2 - Ambient Air Quality, including, but not limited to:

1. ARM 17.8.204 Ambient Air Monitoring
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
7. ARM 17.8.221 Ambient Air Quality Standard for Visibility

8. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

ConocoPhillips must comply with the applicable ambient air quality standards. See Section VI Ambient Air Impact Analysis.

C. ARM 17.8, Subchapter 3 - Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged to an outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, ConocoPhillips shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.

5. ARM 17.8.316 Incinerators. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any incinerator, particulate matter in excess of 0.10 grains per standard cubic foot of dry flue gas, adjusted to 12% carbon dioxide and calculated as if no auxiliary fuel had been used. Further, no person shall cause or authorize to be discharged into the outdoor atmosphere from any incinerator emissions that exhibit an opacity of 10% or greater averaged over 6 consecutive minutes.

6. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. (4) Commencing July 1, 1972, no person shall burn liquid or solid fuels containing sulfur in excess of 1 pound of sulfur per million Btu fired. (5) Commencing July 1, 1971, no person shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions. ConocoPhillips will burn RFG gas, PSA gas, or natural gas, which will meet this limitation.

7. ARM 17.8.324 Hydrocarbon Emissions--Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.

8. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR Part 60, NSPS. ConocoPhillips is considered an NSPS affected facility

under 40 CFR Part 60 and is subject to NSPS Subparts including, but not limited to:

a. Subpart A, General Provisions, applies to all equipment or facilities subject to an NSPS Subpart as listed below.

b. Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units shall apply to all affected boilers at the facility which were constructed after June 19, 1984, are larger than 100 MMBtu/hr, and combust fossil fuel.

c. Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units shall apply to all affected boilers at the facility which were constructed after June 9, 1989, are between 10 MMBtu/hr and 100 MMBtu/hr, and combust fossil fuel.

d. Subpart J, Standards of Performance for Petroleum Refineries, shall apply to:

- All of the heaters and boilers at the ConocoPhillips refinery (except those subject to Subpart Ja);
- The Claus units at the Jupiter sulfur recovery facility (until it becomes subject to Subpart Ja);
- The Refinery Main Plant Relief Flare. Compliance will be in accordance with 40 CFR 60.11(d) in lieu of the requirements of 40 CFR 60.104, 105 and 107 (Civil Action No. H-01-4430 ("ConocoPhillips Consent Decree"), Paragraphs 161 and 162);
- The Jupiter Sulfur Plant Flare (Jupiter Flare, also known as the SRU/Ammonium Sulfide Unit Flare) (ConocoPhillips Consent Decree, Paragraphs 155 and 156) (until it becomes subject to Subpart Ja);
- The FCCU (CO, SO_2, PM and opacity) (ConocoPhillips Consent Decree, Paragraph 54); and
- Any other affected equipment

e. Subpart Ja, Standards for Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, shall apply to:

- New Crude Heater (H-2301);
- New Vacuum Heater (H-2401);
- Wastewater Treatment System Thermal Oxidizer (when firing supplemental RFG);
- No. 1 H_2 Reformer Heater (H-9401);
- Jupiter Sulfur Plant Flare (Jupiter Flare, also known as the SRU/Ammonium Sulfide Unit Flare);
- Jupiter Plant SRU;
- Jupiter ATS Plant;
- Any other affected equipment

f. Subpart Ka, Standards of Performance for Storage Vessels for Petroleum Liquids, shall apply to all volatile organic storage vessels (including

petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after May 18, 1978, and prior to July 23, 1984, for equipment not overridden by 40 CFR 63, Subpart CC. These requirements shall be as specified in 40 CFR 60.110a through 60.115a. The affected tanks include, but are not limited to:

Tank ID	Contents
T-100 *	Asphalt
T-101*	Asphalt
T-102	Naptha
T-104 *	Vacuum Resid

* *Currently exempt from all emission control provisions due to vapor pressure of materials stored.*

g. Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984, for equipment not overridden by 40 CFR 63, Subpart CC. These requirements shall be as specified in 40 CFR Part 60.110b through 60.117b. The affected tanks include, but are not limited to, the following:

Tank ID	Contents
T-35	Slop oil
T-36	(currently out of service)
T-72	Gasoline
T-107*	Residue
T-110	Material with a max true vapor pressure of 11.1 psia
T-162*	Groundwater HC recovery
T-0851	(No. 5 HDS Feed Storage Tank)
T-2909	Gasoline – Low Sulfur
T-3201*	Polymer Modified Asphalt (PMA)

* *Currently exempt from all emission control provisions due to vapor pressure of materials stored*.

h. Subpart UU, Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture, shall apply to, but not be limited to, asphalt storage tank T-3201, and any other applicable storage tanks that commenced construction or modification after May 26, 1981. Asphalt storage tank T-3201 shall comply with the standards in 40 CFR 60.472(c), and 0% opacity, except for one consecutive 15-minute period in any 24-hour period when transfer lines are being blown for clearing. The PMA unit will be operating at 400°F, well under the asphalt's smoking temperature of 450°F; therefore,
the tank vent opacity will always have 0% opacity. There are no record-keeping requirements under this subpart. However, any malfunction must be reported as required under ARM 17.8.110, Malfunctions.

i. Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, shall apply to, but not be limited to, the delayed coker unit, cryogenic unit, hydrogen membrane unit, gasoline merox

unit, crude vacuum unit (until no longer in service), gas oil hydrotreater unit (consisting of a reaction section, fractionation section, and an amine treating section), No.1 Hydrogen Unit (22.0-MMscfd hydrogen plant feed system), Alkylation Unit Butane Defluorinator Project (consisting of heat exchangers X-453, X-223, X-450, X-451, X-452; pump P-646; and vessels D-130, D-359, D-360), PMA process unit, Alkylation Unit Depropanizer Project, new fugitive components associated with boilers B-5 and B-6; the fugitive components associated with the No.2 H_2 Unit and the No.5 HDS Unit; and any other applicable equipment constructed or modified after January 4, 1983.

j. Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, shall apply to all of the fugitive VOC emitting components added in the NCVU project (including the NCVU off-gas compressor) and any other applicable equipment constructed, reconstructed, or modified after November 7, 2006.

k. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply to, but not be limited to, the coker unit drain system, desalter wastewater break tanks, CPI separators, gas oil hydrotreater, No.1 Hydrogen Unit (20.0-MMscfd hydrogen plant), C-23 compressor station, Alkylation Unit Butane Defluorinator Project, Alkylation Unit Depropanizer Project, the new individual drain system in the No.2 H_2 Unit and the No.5 HDS Unit, Tank T-4523, the NCVU individual drain system, the two API separators associated with the NCVU Project, and any other applicable equipment, for equipment not overridden by 40 CFR 63, Subpart CC.

l. All other applicable subparts and referenced test methods

9. <u>ARM 17.8.341 Emission Standards for Hazardous Air Pollutants</u>. ConocoPhillips shall comply with the standards and provisions of 40 CFR Part 61, as listed below:

a. Subpart A, General Provisions applies to all equipment or facilities subject to a NESHAP Subpart as listed below.

b. Subpart FF, National Emission Standards for Benzene Waste Operations shall apply to, but not be limited to, all new or recommissioned wastewater sewer drains associated with the Alkylation Unit Depropanizer Project, the refinery's existing sewer system (including maintenance and water draw down activities of the LSG tank involving liquids that may include small concentrations of benzene), the new individual drain system for the waste streams associated with the No.2 H_2 Unit and the No.5 HDS Unit, Tanks 34 and 35, and the benzene-containing waste streams generated from the NCVU project.

c. Subpart M, National Emission Standard for Asbestos shall apply to, but not be limited to, the demolition and/or renovation of regulated asbestos containing material.

10. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR Part 63, shall comply with the requirements of 40 CFR Part 63, as listed below:

a. Subpart A, General Provisions, applies to all NESHAP source categories subject to a Subpart as listed below.

b. Subpart R, National Emission Standards for Gasoline Distribution Facilities, shall apply to, but not limited to, the Bulk Loading Rack.

c. Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (Refinery MACT I).

d. Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (Refinery MACT II), shall apply to, but not be limited to, the FCCU, and the Catalytic Reforming Unit #2. Subpart UUU does not apply to the Catalytic Reforming Unit #1 as long as the reformer is dormant or the catalyst is regenerated off-site.

e. Subpart EEEE National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline); shall apply to, but not be limited to, Proto storage tanks.

D. ARM 17.8, Subchapter 4 - Stack Height and Dispersion Techniques, including, but not limited to:

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.402 Requirements. ConocoPhillips must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). The proposed heights of the new or altered stacks for ConocoPhillips are below the allowable 65-meter GEP stack height.

E. ARM 17.8, Subchapter 5 - Air Quality Permit Application, Operation and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. ConocoPhillips submitted the appropriate permit application fee for the current permit action.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit, excluding an open burning permit, issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department

may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

F. ARM 17.8, Subchapter 7 - Permit, Construction, and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit alteration to construct, alter or use any air contaminant sources that have the PTE greater than 25 tons per year of any pollutant. ConocoPhillips has the PTE greater than 25 tons per year of PM, PM_{10}, NO_X, CO, VOC, and SO_2; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, alteration, or use of a source. ConocoPhillips submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. ConocoPhillips submitted an affidavit of publication of public notice for the April 12, 2008 issue of *The Billings Gazette*, a newspaper of general circulation in the City of Billings, in Yellowstone County, as proof of compliance with the public notice requirements.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this permit analysis.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving ConocoPhillips of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

10. ARM 17.8.759 Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or altered source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 178.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirement sin ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of intent to transfer, including the names of the transferor and the transferee, is sent to the Department.

15. ARM 17.8.770 Additional Requirements for Incinerators. This rule specifies the additional information that must be submitted to the Department for incineration facilities subject to 75-2-215, MCA.

G. ARM 17.8, Subchapter 8 - Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications -- Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and

any major modification with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.

ConocoPhillips' existing petroleum refinery in Billings is defined as a "major stationary source" because it is a listed source with the PTE more than 100 tons per year of several pollutants (PM, PM_{10}, SO_2, NO_x, CO, and VOCs). ConocoPhillips' proposed modification is defined as a "major modification" because there will be a significant net increase in emissions of PM/PM_{10}, SO_2, and NO_x as shown in the table below. Therefore, ConocoPhillips is subject to the PSD requirements for PM, PM_{10}, SO_2, and NO_x.

Pollutant	Total Project Emissions Increase (TPY)	PSD Significance Level (TPY)	Netting Required?	Total Project Net Emissions (TPY)	Contemporaneous Emission Changes (TPY)	Net Emission Change (TPY)	Significant?
PM	38.84	25	Yes	33.73	28.46	62.19	Yes
PM_{10}	38.84	15	Yes	33.73	28.46	62.19	Yes
SO_2	107.92	40	Yes	106.69	101.48	208.17	Yes
NO_x	140.88	40	Yes	84.56	29.23	113.79	Yes
CO	99.14	100	No	N/A	N/A	N/A	No
VOC	36.10	40 (for ozone)	No	N/A	N/A	N/A	No
H_2S	0.13	10	No	N/A	N/A	N/A	No
Lead	0.02	0.6	No	N/A	N/A	N/A	No

3. ARM 17.8.824 Additional Impact Analysis. (1) The owner or operator shall provide an analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial, and other growth associated with the source or modification. (2) The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the source of modification.

ConocoPhillips submitted the required impact analyses.

H. ARM 17.8, Subchapter 10 – Preconstruction Permit Requirements for Major Stationary Sources of Modifications Located Within Attainment or Unclassified Areas, including, but not limited to:

1. ARM 17.8.1004 When Montana Air Quality Permit Required. (1) Any new major stationary source or major modification which would locate anywhere in an area designated as attainment or unclassified for a NAAQS under 40 CFR 81.327 and which would cause or contribute to a violation of a NAAQS for any pollutant at any locality that does not or would not meet the NAAQS for that pollutant, shall obtain from the Department a MAQP prior to construction in accordance with subchapters 7 and 8 and all requirements contained in this subchapter if applicable.

ConocoPhillips is a major stationary source undergoing a major modification in an area that is designated as attainment or unclassified for a NAAQS under 40 CFR 81.327. The nearby Laurel area is designated as nonattainment for the SO_2

NAAQS under 40 CFR 81.327, however. This nonattainment area consists of a 2.0 km radius around CHS Inc.'s petroleum refinery in Laurel. As shown in ConocoPhillips modeling demonstration, the proposed modifications are below the significant levels defined in ARM 17.8.1001 that would cause of contribute to a violation of the NAAQS in Laurel's designated SO_2 nonattainment area. Therefore, Subchapter 10 requirements do not apply to this permitting action.

I. ARM 17.8, Subchapter 12 - Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any stationary source having:
   a. PTE > 100 TPY of any pollutant;

   b. PTE > 10 TPY of any one HAP, PTE > 25 TPY of a combination of all HAPs, or a lesser quantity as the Department may establish by rule; or

   c. PTE > 70 TPY of PM_{10} in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program Applicability. (1) Title V of the FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204 (1), obtain a Title V Operating Permit. In reviewing and issuing MAQP #2619-24 for ConocoPhillips, the following conclusions were made:

   a. The facility's PTE is greater than 100 TPY for several pollutants.

   b. The facility's PTE is greater than 10 TPY for any one HAP and greater than 25 TPY of all HAPs.

   c. This source is not located in a serious PM_{10} nonattainment area.

   d. This facility is subject to NSPS requirements.

   e. This facility is subject to current NESHAP standards.

   f. This source is not a Title IV affected source, nor a solid waste combustion unit.

   g. This source is not an EPA designated Title V source.

   Based on these facts, the Department determined that ConocoPhillips is subject to the Title V operating permit program. ConocoPhillips' Title V Operating Permit #OP2619-02 was issued Final on July 8, 2008. An application for a modification to this operating permit was submitted on August 21, 2008, concurrently with the MAQP application.

J. MCA 75-2-103, Definitions provides, in part, as follows:

"Incinerator" means any single or multiple-chambered combustion device that burns combustible material, alone or with a supplemental fuel or catalytic combustion assistance, primarily for the purpose of removal, destruction, disposal, or volume reduction of all or any portion of the input material.

"Solid waste" means all putrescible and nonputrescible solid, semisolid, liquid, or gaseous wastes, including, but not limited to...air pollution control facilities...

K. MCA 75-2-215, Solid or hazardous waste incineration - additional permit requirements:

MCA 75-2-215 requires air quality permits for all new solid waste incinerators; therefore, ConocoPhillips must obtain an air quality permit.

MCA 75-2-215 requires the applicant to provide, to the Department's satisfaction, a characterization and estimate of emissions and ambient concentrations of air pollutants, including hazardous air pollutants from the incineration of solid waste. The Department determined that the information submitted in this application is sufficient to fulfill this requirement.

MCA 75-2-215 requires that the Department reach a determination that the projected emissions and ambient concentrations constitute a negligible risk to public health, safety, and welfare. ConocoPhillips completed a health risk assessment based on an emissions inventory and ambient air quality modeling for this proposal. Based on the results of the emission inventory, modeling, and the health risk assessment, the Department determined that ConocoPhillips's proposed wastewater treatment system thermal oxidizer complies with this requirement.

MCA 75-2-215 requires the application of pollution control equipment or procedures that meet or exceed BACT. The Department determined that the proposed incinerator (wastewater treatment system thermal oxidizer) constitutes BACT.

III. BACT Determination

A BACT determination is required for each new or altered source. ConocoPhillips shall install on the new or altered source the maximum air pollution control capability, which is technically practicable and economically feasible, except that BACT shall be utilized.

A BACT analysis was submitted by ConocoPhillips in permit application #2619-24, addressing the available methods of controlling NO_x, SO_2, PM/PM_{10}, $PM_{2.5}$, CO, and VOC emissions from the process heaters, Claus SRU, ATS plant, wastewater treatment system, and cooling water tower. The Department reviewed these methods, as well as previous BACT determinations (via the RACT/BACT/LAER Clearinghouse and state agency decisions). The following control options have been reviewed by the Department in order to make the following BACT determination.

Process Heaters

1. NO_x Emissions:
   NO_x emissions will be formed during the combustion reaction of RFG in the new proposed heaters (New Crude Heater H-2301 and New Vacuum Heater H-2401) and the existing No. 1 and No. 2 H_2 Plant Reformer Heaters (H-9401 and H-9701, respectively). There are three mechanisms of NO_x formation: thermal NO_x, prompt NO_x, and fuel-bound NO_x. Thermal NO_x formation occurs by the high temperature thermal dissociation and subsequent reaction of combustion air molecular nitrogen (N_2) and oxygen (O_2) via the Zeldovich mechanism. Much of the NO_x resulting from the thermal NO_x mechanism is generated in the high temperature zone near the burner and is affected by O_2 concentration, peak temperature, and time of exposure at peak temperature. Thermal NO_x generation increases exponentially with temperature, and above 2,000 ˚F, it is generally the predominant mechanism in combustion processes that involve fuel streams that do not contain significant amounts of chemically bound

nitrogen, such as RFG. Prompt NO_x occurs at the flame front through the relatively fast reaction between N_2 and O_2 molecules in the combustion air and fuel hydrocarbon radicals that are intermediate species formed during the combustion process. Prompt NO_x is usually responsible for no more than 20 ppmv NO_x in RFG fueled combustion equipment. However, because it is an important mechanism in lower temperature combustion processes, it can represent a significant portion of NO_x emissions when emissions are reduced to extremely low levels associated with typical NO_x combustion control techniques. Fuel-bound NO_x is formed by the direct oxidation of organo-nitrogen compounds contained in the fuel stream. RFG typically contains negligible fuel bound nitrogen compounds.

Table III-1 below describes the potential BACT control options used to control NO_x emissions from heaters identified during a search of the RBLC database, a review of EPA's January 19, 2001 Memorandum titled *BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Sulfur Refinery Project* (Tier 2 BACT/LAER Memorandum) and an assessment of recently issued Department BACT determinations. The table lists the control options in order of NO_x reduction potential, with Rank 1 identifying the control option with the highest NO_x emissions reduction potential. The level of NO_x emissions identified in the RBLC database as a result of implementation of these control technologies ranges from 0.0125 pound per million British thermal unit (lb/MMBtu) to 0.6 lb/MMBtu.

TABLE III-1: NO_x BACT Control Hierarchy

Rank	Control Technology	Percent Reduction	Technically Feasible
1	Selective Catalytic Reduction (SCR) with ULNBs	92-96%	Yes
2	Selective Non-Catalytic Reduction (SNCR) with ULNBs	85-93%	No
3	EM_x (formerly $SCONO_x$)	85-95%	No
4	SCR	80-90%	Yes
5	ULNBs	68-84%	Yes
6	SNCR	19-60%	No

SCR with ULNBs:
The top ranked control alternative being considered for the control of NO_x emissions from the heaters is SCR in combination with ULNB. SCR is a post-combustion flue gas treatment technique for the selective catalytic chemical reduction of nitric oxide (NO) and nitrogen dioxide (NO_2) to molecular nitrogen and water vapor. In the SCR process, a reducing agent (aqueous or anhydrous ammonia) is mixed with the combustion device exhaust stream and then passed through a catalyst bed, which serves to lower the activation energies necessary for the NO_x reduction reactions to occur and to increase the NO_x reduction reactions rates. The NO_x and NH_3 are adsorbed onto the catalyst surface to form an activated complex and then the catalytic reaction occurs resulting in nitrogen and water, which are desorbed from the catalyst surface and into the flue gas. Depending on the overall ammonia-to-NO_x ratio, control efficiencies for NO_x ranging from 80 to 90% may be achieved. Although very effective in reducing NO_x emissions, SCR has technical, economic, and environmental difficulties associated with its design, operation, and maintenance.

In regard to the technical difficulties associated with SCR systems, the temperature of the flue gas stream is critical in the design and operation of an SCR unit because a specific type of catalyst must be chosen to ensure optimum NO_x reduction.

Therefore, if the temperature of the flue gas is below the optimum operating window of the selected catalyst, then the NO_x reduction efficiency of the SCR system will decrease and the quantity of ammonia reagent emitted to the atmosphere or available for undesirable side reactions will increase. Conversely, if the temperature of the flue gas is above the optimum operating window of the catalyst, then the ammonia reagent can be oxidized and generate additional NO_x. Furthermore, for any fuel that can contain appreciable levels of sulfur compounds, such as RFG, maintaining the correct SCR operating conditions is a significant concern to avoid generating ammonium salts (ammonium sulfate and bisulfate) formed as byproducts in undesirable side reactions. These salts can cause plugging when they accumulate on the catalyst surface or corrode downstream equipment on which they may condense, and can be generated when the SCR operating temperature is too low because NH_3 that does not react with NO_x is available to react with SO_3. In fact, according to EPA's Tier 2 BACT/LAER Memorandum, a refiner reported that catalyst plugging problems for an SCR system installed on a process heater at its facility have prevented the system from operating at its expected NO_x reduction efficiency. The following are several steps that can be taken to reduce the potential for plugging and corrosion: (1) operate with the lowest ammonia injection levels needed to achieve the desired control performance, (2) reduce the level of sulfur in the fuel gas, (3) ensure proper mixing of the flue gas and the ammonia to eliminate cold surfaces for ammonium salts to condense, and (4) operate at temperatures above the dew point of the ammonium salt. However, the maintenance of additional operating parameters over a variety of combustion unit operating loads and conditions are associated with these options. Moreover, if necessary, additional operating costs would be required to remove the sulfur content in the fuel gas and to provide supplemental heat to ensure an SCR system temperature above the dew point of the ammonium salts.

Several environmental and safety concerns are associated with the operation of an SCR system. SCR applications generally operate with a molar NH_3/NO_x ratio greater than that required by the stoichiometry of the reduction chemical reaction in order to achieve optimal NO_x reduction efficiencies. This operational condition is referred to as ammonia slip and it results in the emission of odorous NH_3 into the atmosphere. Not only is NH_3 odorous, it is a $PM_{2.5}$ precursor that can react in the ambient air to generate fine particulate matter that contributes to regional visibility problems by scattering light and causes adverse human health effects. Additionally, the formation of ammonium salts that is discussed above can cause visible plumes and elevated opacity readings from the stack of the combustion unit. Another environmental concern is that some depleted catalysts may be considered hazardous wastes, and therefore require expensive disposal mechanisms. SCR systems also have significant safety considerations associated with the transportation, storage, and handling of large amounts of anhydrous ammonia.

When SCR is used in combination with ULNBs, the SCR inlet level of NO_x is significantly lower, resulting in an SCR outlet NO_x level of approximately 0.004 lb/MMBtu. The cost effectiveness of utilizing SCR in combination with ULNBs was estimated utilizing vendor quotes and guidance provided in the EPA, OAQPS, *Air Pollution Control Cost Manual*. Table III-2 below lists the estimated cost effectiveness values for the new heaters.

Table III-2 SCR w/ ULNBs Cost Effectiveness

Emissions Unit Description	Capital Expenditure ($)	Annual Operating Cost ($)	NO_x Reduction (tpy)	Cost Effectiveness ($/ton)

New Crude Heater H-2301	1,908,913	609,917	27.19	22,429
New Vacuum Heater H-2401	1,090,807	348,212	9.56	36,429

The proposed new heaters will be equipped with air preheaters and next generation ULNBs having a vendor guaranteed NO_x emission level of 0.039 lb/MMBtu. The installation of ULNBs in the new heaters will result in NO_x emissions reductions of 1.90 and 0.67 tpy, respectively, versus the baseline emissions rates and only $21,145 per year combined annual costs. Applying SCR control in addition to ULNBs for the new heaters could result in a NO_x reduction of an additional 25.29 tpy for the new crude heater and 8.89 tpy for the new vacuum heater. However, due to ammonia slip, approximately 4.68 tpy of ammonia would be emitted from the two heaters. Furthermore, the additional annual costs for installing and operating an SCR would be approximately $595,380 for the new crude heater and $341,604 for the new vacuum heater. These additional costs equate to incremental cost effectiveness values of $23,538 and $38,420, respectively, per ton of additional NO_x reduced, which are not believed to be cost effective. Table III-3 lists the estimated incremental cost effectiveness values of SCR for the proposed new heaters.

Table III-3 SCR w/ ULNBs Incremental Cost Effectiveness

Emissions Unit Description	ULNBs Annual Operating Cost ($)	SCR Annual Operating Cost ($)	ULNBs NO_x Reduction (tpy)	SCR NO_x Reduction (tpy)	SCR Incremental Cost Effectiveness ($/ton)
New Crude Heater H-2301	14,537	595,380	1.90	25.29	23,538
New Vacuum Heater H-2401	6,608	341,604	0.67	8.89	38,420

The No. 1 and No. 2 H_2 Plant heaters are existing sources already equipped with ULNBs. Therefore, see the discussion addressing the addition of SCR to the heaters.

Because of the technical difficulties, environmental concerns, safety issues, and high annual and incremental costs associated with the operation of an SCR unit with ULNBs, this combined control technology alternative was rejected as BACT for the control of NO_x emissions from the new heaters.

SNCR with ULNBs:

The second most stringent alternative for the control of NO_x emissions from the heaters is SNCR in combination with ULNBs. Based on EPA's Tier 2 BACT/LAER Memorandum, NO_x emissions of 0.015 lb/MMBtu or 13 ppmv can theoretically be achieved with the application of SNCR, which equates to an 85-93% reduction in NO_x emissions when compared to uncontrolled baseline emissions. The SNCR process is similar to the SCR process in that a reagent reacts with NO_x to form nitrogen and water vapor. However, SNCR does not utilize a catalyst to promote the chemical reduction of NO_x. The most common reagents used in the SNCR system are urea, aqueous ammonia, and anhydrous ammonia, with the reagents being injected into the flue gas stream within a specific temperature window to ensure optimum reduction of NO_x.

Existing data indicate that, in practice, the NO_x reduction efficiencies of SNCR systems are significantly less than SCR systems. Also, the SNCR process requires extremely high flue gas temperatures (1,600 to 2,100 ˚F) without the addition of other chemicals to increase the temperature window to disassociate NO_x to nitrogen and water vapor. As a result, duct burners would be necessary to raise the flue gas

temperature of the exhaust streams of the heaters, which would result in more combustion pollutant emissions (including NO_x) and additional energy consumption. Moreover, the attainment of proper mixing of the reagent with the flue gas at various combustion unit loads can be difficult. Therefore, numerous design and operational technical difficulties are associated with the SNCR process. Lastly, in regard to environmental impacts, the SNCR process may increase undesirable emission such as CO, N_2O, and NH_3.

This control technology was rejected as BACT for the control of NO_x emissions because: (1) it has not been demonstrated to achieve such theoretical NO_x emission reductions, (2) it has inherent design and operational technical difficulties, and (3) there may be adverse environmental impacts associated with its operation.

EM_x:

The third most stringent alternative for the control of NO_x emissions from heaters is EM_x, the second generation of $SCONO_x$ NO_x absorber technology. EM_x is a catalyst-based post-combustion control, which simultaneously oxidizes CO to CO_2, VOC to CO_2 and water, and NO to NO_2, subsequently adsorbing the NO_2 onto the surface of a catalyst where a chemical reaction removes it from the exhaust stream. According to the vendor data, outlet NO_x concentrations less than 2 ppmv can be achieved by the EM_x system.

EM_x has currently only been demonstrated on natural-gas fired combustion turbines. The technology has not been demonstrated in applications on sources other than turbines, nor on sources firing fuel types other than natural gas (such as RFG). Significant technical differences exist between the RFG-fired process heaters included in the NCVU project, and the single source type for which EM_x has been successfully demonstrated. As a result of these significant differences, EM_x cannot be considered to be a technically feasible control option for the process heaters, and is rejected as BACT for the control of NO_x emissions.

SCR:

The fourth most stringent alternative for the control of NO_x emissions from heaters is SCR. As discussed previously, adverse technical, environmental, and safety issues are associated with the installation and operation of SCR systems for combustion sources firing RFG that counter its selection as BACT. Even though the installation of SCR is not believed to be technically feasible for the four heaters, an economic evaluation has been conducted for the installation of SCR on each of the heaters.

The No. 1 and No. 2 H_2 Plant heaters are existing sources already equipped with ULNBs. The NO_x emissions level permitted for each of the two heaters is 0.03 lb/MMBtu. By equipping the two heaters with SCR, reductions in NO_x emissions are estimated to be 30.29 and 24.48 tpy, respectively. The annual costs for installing and operating SCR systems would be approximately $1,201,177 for the No. 1 H_2 Plant heater and $1,030,685 for the No. 2 H_2 Plant heater, yielding cost effectiveness values of $39,653 and $42,096, respectively, per ton of NO_x reduced.

Table III-4 below documents the cost effectiveness of an SCR system for the two new heaters as well as for the two existing heaters.

Table III-4 Heater SCR Cost Effectiveness

Emissions Unit Description	Capital Expenditure ($)	Annual Operating Cost ($)	NO_x Reduction (tpy)	Cost Effectiveness ($/ton)

New Crude Heater H-2301	1,908,913	595,380	27.08	21,990
New Vacuum Heater H-2401	1,090,807	341,604	9.52	35,892
No. 1 H_2 Heater H-9401	4,772,282	1,201,177	30.29	39,653
No. 2 H_2 Heater H-9701	4,090,527	1,030,685	24.48	42,096

Because of the technical difficulties, environmental concerns, and safety issues, as previously presented, the high annual and cost effectiveness associated with the operation of an SCR unit with the proposed new heaters, and the fact that ULNB can achieve a near level of NO_x reduction at a much lower annual cost than SCR and without comparable technical, environmental, and safety concerns, the SCR alone control technology alternative was rejected as BACT for the control of NO_x.

ULNBs:
The next most stringent control alternative for the control of NO_x emissions from heaters is ULNBs. NO_x emissions reduction combustion control equipment and techniques consist of a range of designs and performance levels, which are dependent on the type of fuel fired in the combustion unit and the function of the combustion source (e.g., boiler, incinerator, process heater, etc.). ULNBs are included in this analysis because they have been demonstrated to be a leading NO_x reduction combustion control technology. ULNBs utilize a staged fuel concept and flue gas recirculation. The recirculation can either inspirate combustion gas from the radiant section into the primary and secondary combustion reaction zones or utilize external flue gas recirculation, both of which serve to rapidly mix the fuel and air near the burner exit while controlling flame temperature. Burners utilizing this technology are commonly called next generation ULNBs. The rapid fuel and air mixing nearly eliminates the formation of prompt NO_x and also virtually eliminates incomplete combustion pollutants (CO and VOC), while the flue gas recirculation minimizes the generation of thermal NO_x by limiting the peak flame temperature due to the lower overall excess oxygen concentration.

Information supplied by burner manufacturers and vendors and EPA's Tier 2 BACT/LAER Memorandum document that ULNBs can achieve NO_x emissions of 0.03-0.04 lb/MMBtu, with the upper range representing combustion devices firing fuel with a high hydrogen content or equipped with an air preheater. For this analysis, a NO_x emissions level of 0.039 lb/MMBtu represents the vendor guarantee for the new crude and vacuum heaters when operated at normal conditions. Both of the new heaters are planned to be equipped with next generation ULNBs and air preheaters. The 0.039 lb/MMBtu emissions level is less than the 40 CFR 60, Subpart Ja NO_x emissions limitation of 40 ppmv (dry basis, corrected to 0% excess air).

As previously stated, the two existing H_2 Plant heaters are already equipped with ULNBs, and the existing air permit requires the heaters to achieve a NO_x emissions level of 0.03 lb/MMBtu or less. Therefore, the heaters are not included in this control technology analysis. The 0.03 lb/MMBtu emissions level is less than 40 CFR 60, Subpart Ja NO_x emissions limitation of 40 ppmv (dry basis, corrected to 0% excess air).

Based on a review of the EPA RBLC database, ULNBs have been recently approved as BACT for several refinery heaters and have been identified as the most common NO_x control technology currently used for combustion sources located at refineries. ULNBs are one of the most effective means of controlling NO_x emissions and do not present the dangers to workers or to the surrounding community that accompany SCR and SNCR. ULNBs could, in some cases, result in a loss in combustion

efficiency. However, for a new heater and burner system, their use can be optimized in the unit design and, thus, result in little or no impact on thermal efficiency. ULNB technology offers petroleum refineries – and industry in general - a low maintenance, relatively low cost solution for effectively reduction NO_x emissions to the atmosphere without resulting in collateral environmental concerns.
The installation and operation of ULNBs is more cost effective than SCR. Therefore, ConocoPhillips proposes next generation ULNBs as BACT for the NO_x emissions from the new crude and vacuum heaters and the existing ULNBs as BACT for the NO_x emissions from the two H_2 Plant heaters. The proposed BACT level of emissions for each of the heaters is the following, which applies during both normal operations and start-up/shut down conditions:

H-2301: 0.039 lb/MMBtu NO_x;
H-2401: 0.039 lb/MMBtu NO_x;
H-9401: 0.03 lb/MMBtu NO_x; and
H-9701: 0.03 lb/MMBtu NO_x.

These emission levels correspond well with the range of emission limits reported from applications using ULNBs found in the RBLC database. While the new crude and vacuum heaters are proposed to have emissions levels slightly higher than the H_2 Plant heaters, the higher levels are a direct result of the air preheat with which the new heaters will be equipped. The air preheat will make the heaters much more efficient than without, and as a result the units will consume less fuel to achieve an equivalent level of process fluid heating than if preheat were not present.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

SNCR:
The least stringent control alternative for the control of NO_x emissions from the heaters is SNCR without the combination of combustion controls. Because SNCR control technology alone would result in a control efficiency lower than each of the other alternative control technologies being considered and it is both technically and economically inferior to the other alternative control technologies being considered, this control technology was rejected as BACT for the control of NO_x emissions for the heaters.

2. SO_2 Emissions:
SO_2 emissions from fuel burning equipment are directly related to the quantity of sulfur in the fuel combusted. The EPA RBLC database and recently issued permits for refining operations indicate several available control options for SO_2 from process heaters, involving either removal of sulfur from the RFG stream or post-combustion control of SO_2. Recent refinery applications listed in the RBLC database involving fuel gas cleanup report a level of sulfur in the RFG ranging from 25 to 250 ppmv. Available control options are listed below in Table III-5.

Table III-5 BACT Control Option for SO_2

Rank	Control Technology	Technically Feasible
1	Augmented fuel gas cleanup – chemical absorption/amine system	Yes
2	Fuel gas cleanup - physical adsorption (Rectisol or Selexol)	Yes
3	Fuel gas cleanup – chemical absorption/amine system	Yes

4	Flue gas desulfurization (FGD)	Yes

The new crude and vacuum heaters, as well as the existing No. 1 H_2 Plant heater (H-9401), will be subject to 40 CFR 60, Subpart Ja, which limits the H_2S content of RFG combusted in fuel gas combustion devices to 60 ppmv on a 365 successive calendar day rolling average. Based on a review of the RBLC data and the existing level of performance achievable by fuel gas treatment systems at the Billings Refinery, this BACT analysis considers the baseline emission rate for demonstrating the average cost effectiveness for controls to correspond to a fuel gas sulfur content of 34 ppmv.

Augmented Fuel Gas Cleanup – Chemical Absorption:
The top ranked control alternative being considered for the control of SO_2 emissions from the heaters is use of an augmented fuel gas cleanup system using chemical absorption. Chemical absorption is currently by far the most common method in use for the removal of sulfur from RFG across the refining industry. The gas stream to be treated is passed through a regenerative solvent, such as methyl diethanolamine (MDEA), which chemically bonds to H_2S and scrubs it from the stream. ConocoPhillips currently operates an amine-based chemical absorption system; the top ranked control alternative would involve construction of a new amine unit to achieve a higher degree of sulfur removal.

Implementing an augmented fuel gas cleanup system would result in a fuel gas sulfur content of 10 ppmv, compared to the baseline level of 34 ppmv. The cost effectiveness of implementing this option was estimated using vendor quotes and guidance provided in the EPA, OAQPS, *Air Pollution Control Cost Manual*. Table III-6 below summaries the estimated cost effectiveness values for each process heater. For the purposes of cost analysis, two new amine treaters, each treating the fuel gas for two of the process heaters, are considered.

Table III-6 Augmented Fuel Gas Cleanup Cost Effectiveness

Source Description	Capital Expenditure ($)	Annual Operating Cost ($)	SO_2 Reduction (tpy)	Cost Effectiveness ($/ton)
New Crude Heater H-2301	2,600,000	349,422	2.75	127,007
New Vacuum Heater H-2401	900,000	120,954	0.97	125,069
No. 1 H_2 Heater H-9401	1,935,551	260,124	1.33	196,016
No. 2 H_2 Heater H-9701	1,564,449	210,251	1.50	140,498

The installation of additional amine treatment would result in the SO_2 emissions reductions as provide in Table III-6 above. The cost effectiveness associated with implementing the control on each of the process heaters is also calculated and summarized in Table III-6. The cost effectiveness is greater than $125,000/ton for the new crude heater and the new vacuum heater and $140,000/ton for the No. 1 and No. 2 H_2 Plant heaters. These costs are not believed to be cost effective. Due to adverse economic impacts associated with implementation of an augmented fuel gas cleanup system, this control is rejected as BACT for SO_2 emissions from the process heaters.

Fuel Gas Cleanup-Physical Absorption:
Physical absorption systems make use of a physical sorbent, as opposed to a chemical reaction, which dissolves the sulfur from the RFG stream. Two technologies available are the Rectisol® process and the Selexol® process.

In the Rectisol® process, methanol cooled to approximately -40˚F absorbs the acid gases from the feed gas under high pressure, usually approaching 1,000 psia. The rich solvent containing the acid gases is then depressurized or steam stripped to release the acid gases, which can then be recovered for further treatment. In the process, the solvent is regenerated for reuse.

The Selexol® process is very similar to Rectisol®, but uses a physical solvent that is a mixture of dimethyl ethers of polyethylene glycol. The process is also more effective at higher operating pressures, which can approach 2,000 psia. Given the much lower feed gas pressure of the RFG stream, the Selexol® solvent capacity (amount of acid gas absorbed per volume of solvent) would be much lower than theoretically achievable.

While physical absorption systems are technically feasible, no installations are known to be operating currently for RFG treatment. The level of control of a physical absorption system is expected to be roughly equivalent to augmenting the chemical absorption (amine treatment) system currently in place at the refinery as discussed previously. Given the amine treatment is the most proven, established technology and has the ability to achieve a similar level of SO_2 control, physical absorption systems are technically inferior and are rejected as BACT for the control of SO_2 emissions from the heaters.

Fuel Gas Cleanup – Chemical Absorption:
The next most stringent control is use of chemical absorption without augmented amine treatment for the RFG supply. As mentioned previously, the new crude and vacuum heaters as well as the existing No. 1 H_2 Plant Heater (H-9401) are subject to an RFG sulfur content limit of 60 ppmv (365-successive calendar day rolling average basis) under 40 CFR 60, Subpart Ja. Similarly, the No. 2 H_2 Plant Heater (H-9701) is subject to an RFG sulfur content limit of 162 ppmv under 40 CFR 60, Subpart J. The No. 1 H_2 Plant Heater (H-9401) and the No. 2 H_2 Plant Heater (H-9701) also have the capability to combust PSA offgas and natural gas, both of which have much lower sulfur concentrations than the RFG stream.

Application of an amine-based chemical absorption system can achieve a RFG sulfur content of 34 ppmv, as demonstrated by the existing system at the Billings Refinery. No adverse energy or economic impacts are associated with its use. As mentioned previously, amine treatment is the most proven, established technology for SO_2 emissions control from RFG combustion. Therefore, ConocoPhillips proposes compliance with an RFG sulfur content limit of 34 ppmv under normal operation as BACT for SO_2 emissions from the process heaters. This level corresponds to the actual average H_2S concentration measured from January 2005 to May 2008 at the Billings Refinery, plus 2.5 standard deviations. The 2.5 standard deviations account for variations in crude slate sulfur contents and amine treating efficiency, as well as other sulfur compounds (e.g. mercaptans) contained in the RFG. Though no site-specific data is available to quantify mercaptan concentrations in the RFG, their presence (as well as the presence of other sulfur-containing compounds) results in direct SO_2 emissions from the process heaters.

Since the RFG sulfur content can vary greatly depending on refinery operations, ConocoPhillips proposes a separate BACT level for start-up/shutdown conditions. Consistent with 40 CFR 60, Subpart Ja short-term emissions limitation, ConocoPhillips proposes that the heaters comply with a 162 ppmv (3-hour average) limitation as BACT for SO_2 emissions during start-up/shutdown conditions.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

Flue Gas Desulfurization (FGD):
The least stringent control option for SO_2 emissions from the process heaters does not involve removing sulfur from the RFG, but instead removing SO_2 from the flue gas before it is emitted to the atmosphere. With this technology, the flue gas is passed through a scrubber, which relies on a chemical reaction between the SO_2 and a sorbent to remove SO_2 from the stack gas. FGD systems can be classified as either wet or dry.

In a wet scrubber, a liquid sorbent (typically an alkaline slurry of limestone) is sprayed into the flue gas in an absorber vessel. As the exhaust gas comes into direct contact with the sorbent, SO_2 reacts with the sorbent to form calcium sulfite and calcium sulfate, which is then dropped out of the gas stream as a precipitate. The resulting wet solid byproduct can either be further treated and disposed of as a waste, or oxidized to form a gypsum byproduct.
In a dry scrubber, particles of an alkaline sorbent are injected into the flue gas. Either a slurry of alkaline reagent is atomized into the flue gas, or a dry sorbent is directly injected. The SO_2 reacts with the sorbent and forms a dry solid byproduct. This resulting dry material must be collected in a downstream particulate control device, such as an electrostatic precipitator or fabric filter.

While FGD systems have been used effectively in some applications (particularly solid fossil fuel combustion), the efficiency achievable to the new crude and vacuum heaters and existing H_2 plant heaters is limited due to the dilute SO_2 concentrations in the heaters' exhaust streams. Because FGD would result in a lower control efficiency than the other control technologies under consideration, it was rejected as BACT for the control of SO_2 emissions from the heaters.

3. PM/PM_{10} Emissions:
A review of the EPA RBLC database indicates that the only emissions control technique utilized for PM/PM_{10} emissions from gaseous fuels combustion is good combustion practices and the use of clean burning fuels. The emissions level resulting from the implementation of this technique ranges from 0.005 to 0.023 lb/MMBtu across all types of gaseous fuel. The RBLC database includes 0.0075 lb/MMBtu as the lowest corresponding emissions level for process heaters firing RFG. Therefore, ConocoPhillips proposes to combust clean burning fuels (RFG, natural gas, and PSA offgas), utilize good combustion practices and engineering design, and achieve an emissions level of 0.0075 lb/MMBtu as BACT for PM/PM_{10} emissions from heaters.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

4. $PM_{2.5}$ Emissions:
Fine particles in the atmosphere are comprised of a complex mixture of components. $PM_{2.5}$ can be classified as either primary or secondary. Primary $PM_{2.5}$ contains both a filterable and a condensable component. Filterable $PM_{2.5}$ is in particulate form

when emitted and can be collected on the filter of a sample train (such as that used in performing sample analyses according to EPA Reference Method 201A). Condensable $PM_{2.5}$ is a vapor at stack temperature, but condenses into liquid or solid form when cooled at the stack exit. Condensable $PM_{2.5}$ can be collected downstream of a filter in a sampling train when the sample stream is cooled (such as when performing a sample analysis according to EPA Reference Method 202). Secondary $PM_{2.5}$ forms in the atmosphere as a result of chemical reactions involving the $PM_{2.5}$ precursors SO_2, NO_x, ammonia, and VOC. Generally, secondary $PM_{2.5}$ is distinguished from condensable $PM_{2.5}$ by the time and/or distance from the stack required for formation. The same chemical species (SO_2, NO_x, ammonia, and VOC), however, are responsible for both.

On May 8, 2008, EPA promulgated final rules related to the implementation of $PM_{2.5}$ NSR requirements. The final rule establishes that stationary sources undergoing NSR review must address directly emitted $PM_{2.5}$, as well as the pollutants responsible for secondary $PM_{2.5}$ according to the following:

SO_2 – regulated;

NO_x – regulated unless a state demonstrates that NO_x emissions are not a significant contributor to the formation of $PM_{2.5}$ for an area(s) in the state;

VOC – not regulated unless a state demonstrates that VOC emissions are a significant contributor to the formation of $PM_{2.5}$ for an area(s) in the state; and

Ammonia – not regulated unless a state demonstrates that ammonia emissions are a significant contributor to the formation of $PM_{2.5}$ for an area(s) in the state.

a. Primary:
As discussed above for PM/PM_{10}, the only control technique implemented for the control of particulate emissions from gaseous fuels combustion is good combustion practices and the use of clean burning fuel. Given that PM from gaseous fuel combustion is generally understood to be less than 1 µm in size, this control option also serves as a control for primary $PM_{2.5}$. Therefore, ConocoPhillips proposes to combust clean burning fuels (RFG, natural gas, and PSA offgas), utilize good combustion practices and engineering design, and achieve an emissions level of 0.0075 lb/MMBtu as BACT for primary filterable $PM_{2.5}$ emissions from the heaters.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

b. Secondary:
Control options for secondary $PM_{2.5}$ precursors (NO_x and SO_2) have already been addressed since BACT reviews were required for NO_x and SO_2 emissions from process heaters. These same control options also act to control secondary $PM_{2.5}$ emissions resulting from NO_x and SO_2 precursors.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

5. CO Emissions:
In combustion processes, CO is emitted from localized areas of the combustion zone where the temperature or oxygen content is insufficient for complete combustion. As a general rule, higher combustion temperatures and greater turbulence of the fuel/air mixture in the combustion zone act to reduce CO emissions. The conditions that contribute to CO formation can result in lower NO_x emissions by reducing "hot spots" in the combustion zone that cause thermal NO_x generation. However, current burner design has virtually eliminated this inverse relationship allowing vendors to guarantee low CO emissions from ULNBs.

A review of the EPA RBLC database indicates that the following are available CO emission control technologies for the heaters: oxidation catalyst and good combustion unit design, maintenance, and operation. The level of CO emissions identified in the RBLC database as a result of implementation of these control technologies ranges from 0.01 to 0.2 lb/MMBtu.

Oxidation catalyst can be utilized as a post-combustion CO emissions control technology with a control efficiency ranging from 50 to 90%. The typical oxidation catalyst for CO is rhodium or platinum, and the acceptable operating temperature for the catalyst ranges from 400 to 1,250 ˚F. However, a greater catalyst volume is required below 600 ˚F to achieve the same emissions reduction performance that would occur at higher, more optimal temperature. Because the new crude and vacuum heaters will incorporate air preheat for improved thermal efficiency and the existing H_2 Plant heaters are designed with heat recovery steam generation components, the catalyst would either require placement prior to existing heat recovery systems/equipment or after new flue gas reheat equipment. In either of these cases, an incremental increase in combustion emissions would potentially occur, partially or completely negating the CO emissions reduction that the oxidation catalyst would provide for the heaters. Additionally, the installation of oxidation catalyst in flue gases containing greater than trace levels of SO_2 will result in the poisoning and deactivation of the catalyst and increase the conversion of SO_2 to SO_3. The increased conversion of SO_2 to SO_3 increases condensable particulate matter emissions and flue gas equipment corrosion rates. Based on the technical difficulties and potentially adverse collateral air emissions impacts of oxidation catalyst, use of oxidation catalyst is rejected as BACT for CO.

ConocoPhillips proposes to comply with ARM 17.8.752 for the new heaters and modified existing heaters the only other CO control that has been demonstrated on process heaters; the combustion of clean burning fuels (i.e., RFG, natural gas, and PSA offgas) and utilization of good combustion unit design, maintenance, and operation. The emissions level for CO from each of the heaters is listed in Table III-7 below, both for normal operation and operation during start-up and shutdown conditions.

Table III-7 - CO BACT Emissions Level Summary

Emissions Unit Description	CO Emissions Level – Normal Operation (lb/MMBtu)	CO Emissions Level – Su/SD Conditions (lb/MMBtu)
New Crude Heater H-2301	0.011 (365-day rolling average)	0.30 (daily average)
New Vacuum Heater H-2401	0.011 (365-day rolling average)	0.30 (daily average)
No. 1 H_2 Heater H-9401	0.015 (365-day rolling average)	1.7 (daily average)
No. 2 H_2 Heater H-9701	0.015 (365-day rolling average)	1.7 (daily average)

Due to the varying air/fuel ratios and degree of turbulence within the combustion

zone that can be present at unit turndown (during start-up and shutdown events), higher emissions of CO may result than during normal operations when these key parameters affecting CO formation are optimized. This phenomenon is reflected in the higher limits representing CO BACT during start-up and shutdown conditions.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

6. VOC Emissions:
The same type of poor design and operations that contribute to elevated CO emissions from gaseous fuel combustion devices contribute to VOC emissions. A review of the EPA RBLC database indicates the following are available VOC emission control technologies for heaters combustion gaseous fuels: oxidation catalyst and good combustion unit design, maintenance, and operation.

Based on the same technical difficulty reasons discussed above for the application of oxidation catalyst to control CO emissions from the heaters, ConocoPhillips proposes the combustion of clean burning fuels (RFG, natural gas, and PSA offgas) and utilization of good combustion unit design, maintenance, and operation as compliance with the provisions of ARM 17.8.752 for VOC emissions.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

Claus SRU

1. NO_x Emissions:
NO_x is generated from the combustion of fuel gas in the SRU tail gas thermal oxidizer. The TGTU thermal oxidizer in the Claus SRU is fired with RFG and acts to convert the H_2S not converted into elemental sulfur by the SRU into the less toxic SO_2 prior to venting to the atmosphere. A review of the EPA RBLC database indicates that proper equipment design and operation of the SRU and low NO_x burners in the TGTU thermal oxidizer are available control options for controlling NO_x emissions from a Claus SRU. As a combustion source, the control options for NO_x identified for the refinery process heaters can also apply to the thermal oxidizer (post-combustion controls including SCR, EM_x, and SNCR). Finally, operation of the SRU without the thermal oxidizer would completely eliminate the NO_x emissions resulting from combustion, but would alternatively result in H_2S emissions from the SRU. Because the existing TGTU is designed to operate with the thermal oxidizer, the removal of the oxidizer is not discussed further as a BACT control option for NO_x.

Post combustion control equipment, including SCR, EM_x, and SNCR, are not considered to be technically feasible options for control of NO_x from the TGTU thermal oxidizer. The oxidizer has significant technical differences from the combustion units (e.g., boilers and process heaters) where post-combustion controls are routinely applied. Finally, the exhaust from the TGTU thermal oxidizer may potentially contain high concentrations of SO_2, which would poison catalysts used in SCR and EM_x systems. Therefore, post-combustion controls are rejected as BACT for NO_x emissions from the TGTU thermal oxidizer.

The most stringent technically feasible option that remains for control of NO_x emissions from the SRU is proper equipment design and operation, combined with

continued operation of the existing low NO_x burners in the TGTU thermal oxidizer. Therefore, ConocoPhillips proposes proper equipment design and operation of the SRU combined with the continued operation of low NO_x burners in the tail gas thermal incinerator as BACT for NO_x emissions from the Claus SRU.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

2. SO_2 Emissions:
The Billings Refinery Claus SRU will be subject to the Claus sulfur recovery plant SO_2 emissions limitation of 250 ppmv at 0% excess air in 40 CFR 60, Subpart Ja, which is the same emissions limitation included in the currently applicable Subpart J. This outlet concentration is documented by the EPA as consistent with an overall sulfur recovery efficiency of 99.9%. Finally, the current permit for the refinery includes a limit on the SO_2 concentration from the Jupiter SRU/ATS Plant Main Stack of 167 ppmv at 0% O_2 (on a rolling 12-hour average), which is approximately 33% lower than the Subpart Ja limitation.

A review of the EPA RBLC database indicates that a Claus unit equipped with a TGTU is the most stringent control technology for SO_2 emissions from a Claus SRU. The reported outlet SO_2 concentrations from this technology range from 150 to 250 ppmv at 0% excess air. Several alternative tail gas treatment technologies, some similar to the TGTU with which the Claus SRU is equipped, exist, but these technologies do not necessarily achieve more stringent SO_2 emissions control. Since the alternative TGTUs do not represent a more stringent control technology when compared to the TGTU currently in place at the facility, they are not considered further as BACT for SO_2.

As part of the BACT review, ConocoPhillips reviewed the historic performance of the existing control system and actual monitoring data on the Jupiter SRU/ATS Plant Main Stack and has determined that the control system is capable of meeting 150 ppmv at 0% O_2 (on a rolling 365-day average). Therefore, ConocoPhillips is proposing to add a limit of 150 ppmv at 0% O_2 (on a rolling 365-day average) for the Jupiter SRU/ATS Plant Main Stack, to be consistent with the BACT limit listed in the RBLC database.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

3. PM/PM_{10} Emissions:
PM is generated in the TGTU thermal oxidizer from the combustion of fuel gas and sulfur-containing vent gases from the TGTU. Based on a review of the EPA RBLC database, proper equipment design and operation, good combustion practices, and burning of gaseous fuels are the most stringent control techniques for controlling PM/PM_{10} emissions from a Claus SRU. Therefore, ConocoPhillips proposes proper equipment design and operation (which includes the TGTU scrubbing tower and gas filters), good combustion practices, and burning of gaseous fuels as BACT for PM/PM_{10} emissions from the Claus SRU.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable

of achieving the appropriate emission standards.

4. $PM_{2.5}$ Emissions:

   a. Primary:
   Primary $PM_{2.5}$ is generated from the combustion in the TGTU thermal oxidizer. As discussed above for PM/PM_{10}, the only control technique implemented for the control of particulate emissions from gaseous fuels combustion is proper equipment design and operation, good combustion practices, and burning of gaseous fuels. Since PM from gaseous fuel combustion is generally understood to be less than 1 µm in size, this control option also serves as a control for primary $PM_{2.5}$. Therefore, ConocoPhillips proposes proper equipment design and operation (which includes the TGTU scrubbing tower and gas filters), good combustion practices, and burning of gaseous fuels as BACT for primary $PM_{2.5}$ emissions from the Claus SRU.

   The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

   b. Secondary:
   Control options for $PM_{2.5}$ precursors (NO_x and SO_2) have already been addressed, since BACT reviews were required for NO_x and SO_2 emissions from the SRU. These same control options also act to control secondary $PM_{2.5}$ emissions resulting from NO_x and SO_2 precursors.

   The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

5. CO Emissions:
   CO is generated from the combustion of fuel gas in the TGTU thermal oxidizer. A review of the EPA RBLC database provides that proper equipment design and operation, combined with good combustion practices and burning of gaseous fuel, is the most stringent control technique for controlling CO from a Claus SRU. As a combustion source, an oxidation catalyst, as previously identified for the refinery process heaters, can also apply to the thermal oxidizer. Finally, operation of the SRU without the TGTU thermal oxidizer would completely eliminate CO emissions resulting from combustion, but would result in H_2S emissions from the SRU. Because the existing TGTU is designed to operate with the thermal oxidizer, the removal of the oxidizer is not discussed further as a BACT control option for CO.

   Oxidation catalyst is not considered to be technically feasible option for control of CO from the thermal oxidizer. As mentioned in the NO_x BACT discussion above, the exhaust from the TGTU thermal oxidizer may potentially contain high concentrations of SO_2, which would poison the oxidation catalyst. Therefore, oxidation catalyst is rejected as BACT for CO emissions from the thermal oxidizer.

   ConocoPhillips therefore proposes to comply with ARM 17.8.752 for CO emissions from the Claus SRU by the most stringent technically feasible option that remains, namely proper equipment design and operation, combined with good combustion practices and burning of gaseous fuel.

   The Department has determined that the control options selected have controls and

control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

ATS Plant

1. NO_x Emissions:
A review of the EPA RBLC database indicates that proper equipment design and operation of the SRU and low NO_x burners in the TGTU thermal oxidizer are available options for controlling NO_x emissions from an SRU. The ATS Plant does not have a TGTU thermal oxidizer. Instead, the plant has an incinerator that receives a combination of exhaust gas from an upstream Claus boiler and acid gas from the refinery. As a combustion source, the control options for NO_x identified for the refinery process heaters can also apply to the ATS incinerator (post combustion controls including SCR, EM_x, and SNCR). Operation of the ATS plant without the incinerator is not technically feasible since the incinerator converts H_2S to SO_2, which is a necessary reactant in the ATS production process.

Post combustion control equipment, including SCR, EM_x, and SNCR, is not considered to be a technically feasible option for control of NO_x emissions from the incinerator. The unit has significant technical differences from the combustion units (e.g., boilers and process heaters) where post-combustion controls are routinely applied. Finally, the outlet from the incinerator contains levels of SO_2, which would poison catalysts used in SCR and EM_x systems. Therefore, post-combustion controls are rejected as BACT for NO_x emissions from the ATS Plant. ConocoPhillips proposes proper equipment design and operation of the ATS Plant as BACT for NO_x.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

2. SO_2 Emissions:
A review of the EPA RBLC database indicates that a TGTU for an SRU is the most stringent control technology for SO_2 emissions. The ATS plant at the Billings Refinery is subject to the Claus sulfur recovery plant SO_2 emission limitation of 250 ppmv at 0% O_2 in 40 CFR 60, Subpart Ja, which is documented by the EPA as being consistent with an overall sulfur recovery efficiency of 99.9% Finally, the current permit for the refinery specifies that the SO_2 emissions from the Jupiter SRU/ATS Plant Main Stack cannot exceed 167 ppmv at 0% O_2 (on a rolling 12-hour average), which is approximately 33% lower than the Subpart Ja limitation.

As discussed previously, ConocoPhillips performed a review of the historic performance of the existing control system and actual monitoring data on the Jupiter SRU/ATS Plant Main Stack and has determined that the control system is capable of meeting 150 ppmv at 0% O_2 (on a rolling 365-day average). Therefore, ConocoPhillips is proposing to add a limitation of 150 ppmv at 0% O_2 (on a rolling 365-day average) as an addition to the current limit of 167 ppmv at 0% O_2 (on a rolling 12-hour average) for the Jupiter SRU/ATS Plant Main Stack, to be consistent with the BACT limit listed in the RBLC database.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

3. PM/PM_{10} Emissions:

PM is generated in the ATS incinerator from the combustion of fuel gas and sulfur-containing vent gases. A review of the EPA RBLC database provides that proper equipment design and operation, good combustion practices, and burning of gaseous fuels are the most stringent control techniques for controlling PM/PM_{10} emissions from an SRU. As mentioned previously, operation of the ATS Plant without the incinerator is not technically feasible since the incinerator converts H_2S to the SO_2 needed as a reactant in the ATS production process and, therefore, is not discussed further as a BACT control option for PM/PM_{10}. Therefore, ConocoPhillips proposes proper equipment design and operation (which includes the TGTU scrubbing tower and gas filters), good combustion practices, and burning of gaseous fuels as BACT for PM/PM_{10} emissions from the ATS plant.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

4. $PM_{2.5}$ Emissions:
   a. Primary:

      Primary $PM_{2.5}$ is generated from the combustion in the ATS incinerator. As discussed above for PM/PM_{10}, the most stringent control technique implemented for the control of particulate emissions from an SRU is proper equipment design and operation, good combustion practices, and burning of gaseous fuels. Since PM from gaseous fuel combustion is generally understood to be less than 1 µm in size, this control option also serves as a control for primary $PM_{2.5}$. Therefore, ConocoPhillips proposes proper equipment design and operation (which includes the TGTU scrubbing tower and gas filters), good combustion practices, and burning of gaseous fuels as BACT for primary $PM_{2.5}$ emissions from the ATS plant.

      The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

   b. Secondary:
      Control options for $PM_{2.5}$ precursors (NO_x and SO_2) have already been addressed, since BACT review was required for NO_x and SO_2 emissions from the ATS plant. These same control options also act to control secondary $PM_{2.5}$ emissions resulting from NO_x and SO_2 precursors.

      The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

5. CO Emissions:
   A review of the EPA RBLC database provides that proper equipment design and operation, good combustion practices, and burning of gaseous fuels are the most stringent control techniques for controlling CO from a Claus SRU, which represents the front half (and CO emissions generating portion) of the ATS Plant. Oxidation catalyst, as previously identified for the refinery process heaters, is also an available control of CO emissions from the ATS plant.

   Oxidation catalyst is not considered to be technically feasible option for control of

CO from the ATS incinerator. As mentioned in the NO_x BACT discussion above, the composition of incinerator exhaust stream contains levels of SO_2 used as a reactant in the ATS production process. Since the SO_2 would poison the oxidation catalyst, it is rejected as BACT for CO emissions from the ATS Plant. Therefore, ConocoPhillips proposes proper equipment design and operation and good combustion practices as compliance with ARM 17.8.752 for CO emissions from the ATS Plant.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

Wastewater Treatment System:

1. NO_x Emissions – Thermal Oxidizer:
   The role of the thermal oxidizer is to destruct organic compounds and acid gases in the gaseous vent streams from the wastewater treatment plant. The unit operates with a VOC destruction efficiency of 99%, constituting BACT-level control for VOC emissions from wastewater treatment. Therefore, a balance must be reached between controlling NO_x, CO, SO_2, and PM emissions from the thermal oxidizer and fulfilling the organic emissions reduction purpose of the oxidizer.
   A review of the EPA RBLC database indicates that proper equipment design and operation and low NO_x burners are available options for controlling NO_x emissions from a thermal oxidizer. Reported NO_x emission limits range from 0.025 lb/MMBtu to 1.0 lb/MMBtu. As a combustion device, other available control options for NO_x include post-combustion controls, such as SCR and SNCR, and combustion modifications, such as staged combustion and optimized fuel-air ratio. Finally, operation without the thermal oxidizer would result in the complete removal of NO_x emissions, but also would result in uncontrolled VOC and H_2S emissions from wastewater emissions sources. Given that operation without a thermal oxidizer runs counter to the purpose of the unit, it is not discussed further as a BACT control option for NO_x.

   Combustion modifications generally act to reduce flame temperature to suppress NO_x formation. However, a temperature of 1,400 ˚F is required within the unit for the required destruction of VOC and H_2S. The thermal oxidizer design utilizes a combustion chamber and dwell chamber coupled with a highly turbulent design and optimized fuel to air ratio for efficient destruction of VOC. Process gas fumes are drawn into the combustion chamber, around the burner profile, through a venturi section, into the dwell chamber. The treated process gas is then sent to the atmosphere via the exhaust stack. The burner uses external combustion air to provide even heating and is designed to promote mixing. The design creates a tremendous amount of turbulence leading to temperature uniformity within the combustion chamber, eliminating temperature stratification and providing relatively higher destruction at lower operating temperatures. Staged combustion is not considered to be technically feasible because the thermal oxidizer design only consists of one burner. Therefore, it is rejected as BACT for control of NO_x emissions from the thermal oxidizer.

   The technical feasibility of post-combustion controls such as SCR and NSCR is questionable for a small thermal oxidizer unit such as the one proposed as part of the NCVU Project. Even though these control options may or may not be feasible, for the purposes of this BACT analysis it is assumed they are. The next step in the BACT analysis is an economic evaluation for the installation of post-combustion controls.

The cost analysis performed as part of this BACT review assumes that a SCR or NSCR control device exists that is capable of controlling NO_x emissions with a 90% removal efficiency, has a total capital cost of only $100,000, and has annual operating and maintenance costs of $0. These assumptions provide an extremely conservative, hypothetical case to judge whether additional controls are potentially cost effective. This analysis is based on a baseline level of emissions reflecting current proposed operations of 25 ppmv NO_x exhaust concentration. Table III-8 below provides a summary of the cost effectiveness of a hypothetical post-combustion control system.

Table III-8 – Thermal Oxidizer Post-Combustion NO_x Control Cost Effectiveness

Emissions Unit Description	Capital Expenditure ($)	Annual Operating Cost ($)	Total Pollutant Reduction (tpy)	Cost Effectiveness ($/ton)
Wastewater Thermal Oxidizer	100,000	0	0.43	45,266

Even given the overly conservative assumptions made in this evaluation, additional controls are demonstrated to not be cost effective due to the high $/ton value resulting for the assumed control. Since no control systems are known to be available at such a nominal cost, the actual cost effectiveness of installing a NO_x control device such as SCR or SNCR would be significantly higher than the $/ton value shown in Table III-8. Therefore, post-combustion controls are rejected as BACT for control of NO_x emissions from the thermal oxidizer.

Since additional combustion modifications are not technically feasible and post-combustion controls are not cost effective, ConocoPhillips proposes proper equipment design and operation and a 25 ppmv NO_x emission limitation at 8% O_2 as BACT for NO_x emissions from the thermal oxidizer during normal operations. Due to operational requirements during proper unit start-up and shutdown, ConocoPhillips proposes a NO_x emissions limitation of 1,000 ppmv at 8% O_2 during start-up and shutdown.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

2. SO_2 Emissions – Thermal Oxidizer:
SO_2 emissions from fuel burning equipment are directly related to the quantity of sulfur in the materials combusted. The EPA RBLC database provides that fuel sulfur content limits and minimization of the sulfur content of the waste stream combusted are considered BACT for SO_2 emissions from thermal oxidizers combusting gaseous fuels and waste streams.

The thermal oxidizer will either fire RFG or natural gas. Additionally, the waste gas stream combusted will have minimal sulfur containing compounds (estimated as a 4 scfm vent stream from storage tank breathing with an H_2S content of 5 ppmv). As explained previously, ConocoPhillips is proposing as BACT for control of SO_2 emissions from the NCVU process heaters an RFG sulfur limit of 34 ppmv during normal operations, and 162 ppmv (3-hour average) during start-up and shutdown conditions (consistent with the short-term limit of 40 CFR 60, Subpart Ja). Since the

thermal oxidizer will be fired with the same fuel, these same limits are proposed as BACT for the control of SO_2 emissions from the thermal oxidizer.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

3. PM/PM_{10} Emissions – Thermal Oxidizer:
A review of the EPA RBLC database provides proper equipment design and operation and good combustion practices as control technologies for gaseous fuel thermal oxidizers controlling gaseous waste streams. As part of proper operation, a preventative maintenance program can be implemented according to manufacturer's specifications. As a combustion device, other available control options for PM include post-combustion controls, such as a baghouse, wet electrostatic precipitator, wet scrubber, or cyclone (inertial separation). Finally, operation without the thermal oxidizer would result in the complete removal of PM emissions, but also would result in uncontrolled VOC and H_2S emissions from wastewater emissions sources. Given that operation without a thermal oxidizer runs counter to the purpose of the unit, it is not discussed further as a BACT control option for PM.
The technical feasibility of post-combustion controls such as a baghouse, wet electrostatic precipitator, wet scrubber, or cyclone is questionable for a small thermal oxidizer unit such as this one controlling wastewater emissions. Even though these control options may or may not be feasible, for the purposes of this BACT analysis it is assumed they are. The next step in the BACT analysis is an economic evaluation for the installation of post-combustion controls.

The cost analysis performed as part of this BACT review assumes that a post-combustion control device exists that is capable of controlling PM_{10} emissions with a 99% removal efficiency, has a total capital cost of only $10,000, and has annual operating and maintenance costs of $0. These assumptions provide an extremely conservative, hypothetical case to judge whether additional controls are potentially cost effective. This analysis based on a baseline level of emissions reflecting current proposed operations of 0.011 lb/hr of PM_{10}. Table III-9 below provides a summary of the cost effectiveness of a hypothetical post-combustion control system.

Table III-9 – PM_{10} Post-Combustion Control Cost Effectiveness

Emissions Unit Description	Capital Expenditure ($)	Annual Operating Cost ($)	Total Pollutant Reduction (tpy)	Cost Effectiveness ($/ton)
PM_{10} Post-Combustion Control Device	10,000	0	0.05	39,341

Even given the overly conservative assumptions made in this evaluation, the cost effectiveness presented in Table III-9 shows that additional controls are not cost effective, given the high $/ton value that would result from implementation of this theoretical control. Since no control systems are known to be available at such a nominal cost, the actual cost effectiveness of installing a PM control device such as a baghouse, wet electrostatic precipitator, wet scrubber, or cyclone would be higher than the $/ton value shown in the Table III-9. Therefore, post-combustion controls are rejected as BACT for control of PM emissions from the thermal oxidizer.

Since post-combustion controls have been shown not to be cost effective,

ConocoPhillips proposes proper equipment design and operation (including preventative maintenance of the unit according to manufacturer's specifications and an optimized fuel-to-air ratio) and good combustion practices as BACT for PM/PM_{10} emissions from the thermal oxidizer, reflected in a PM/PM_{10} emissions rate of 0.011 lb/hr.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

4. $PM_{2.5}$ Emissions – Thermal Oxidize:r
   a. Primary:
      As discussed above for PM/PM_{10}, proper equipment design and operation and good combustion practices (including a preventative maintenance program and an optimized fuel-to-air ratio) is an established control technology for gaseous fuel thermal oxidizers controlling gaseous waste streams. Other available control options include post-combustion controls, such as a baghouse, wet electrostatic precipitator, wet scrubber, or cyclone (inertial separation). Given that PM from gaseous fuel combustion is generally understood to be les than 1 µm in size, these control options also serve as control for primary $PM_{2.5}$. Therefore, relying on the analysis previously presented, ConocoPhillips proposes proper equipment design and operation (including preventative maintenance of the unit according to manufacturer's specifications and an optimized fuel-to-air ratio) and good combustion practices as BACT for primary $PM_{2.5}$ emissions from the thermal oxidizer, reflected in a $PM_{2.5}$ emissions rate of 0.011 lb/hr.

      The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

   b. Secondary:
      Control options for $PM_{2.5}$ precursors (NO_x and SO_2) have already been addressed, since BACT review was required for NO_x and SO_2 emissions from the thermal oxidizer. These same control options also act to control secondary $PM_{2.5}$ emissions resulting from NO_x and SO_2 precursors.

      The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

5. CO Emissions – Thermal Oxidizer:
   In combustion processes, CO is emitted from localized areas of the combustion zone where the temperature or oxygen content is insufficient for complete combustion. As a general rule, higher combustion temperatures and greater turbulence of the fuel/air mixture in the combustion zone act to reduce CO emissions. The thermal oxidizer is being installed to destroy a gaseous waste stream; therefore, the burner will be designed and operated to ensure complete combustion of the fuel gas and waste gas. CO formation through incomplete combustion will inherently be minimized by the burner design. A review of the EPA RBLC database indicates that proper design and operation and good combustion practices represent available CO emission control technologies for thermal oxidizers combusting gaseous fuels and waste streams.

   As described above, the thermal oxidizer burner design incorporates elements to

provide even heating, promote mixing, and provide a high velocity to create a tremendous amount of turbulence with the combustion chamber. Additionally, an optimized fuel to air ratio is used to promote complete combustion. ConocoPhillips therefore proposes proper burner design and operation, optimized fuel to air ratio, good combustion practices, and a 25 ppmv CO emission limit as BACT for CO emissions from the thermal oxidizer. Due to operational requirements during proper unit start-up and shutdown, ConocoPhillips proposes a CO emissions limitation of 1,000 ppmv at 8% O_2 as BACT during start-up and shutdown operations.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.
Theoretically, an additional thermal oxidizer would be used to control CO emissions from this thermal oxidizer. Considering the intent of thermal oxidizers is the complete combustion of VOC emissions, the complete conversion of CO is also an inherent design trait. An additional thermal oxidizer for CO emissions control from a thermal oxidizer is not practical and would create additional combustion pollutant emissions.

6. VOC Emissions:
   a. Wastewater Treatment System:

      The NCVU project includes the installation of a new wastewater treatment system to treat the wastewater stream from the desalters in the new Crude Unit. The new wastewater treatment system will consist of two API separators and a primary dissolved air flotation (DAF) vessel. In addition to these new pieces of equipment, the refinery's existing aeration system will be upgraded with the addition of an aeration system compressor and fine bubbler diffuser systems at two biotanks. A search of the EPA RBLC database provides that BACT for wastewater treatment equipment such as the API separators and the DAF vessel are closed system and control device configurations, floating roofs for API separators, or pollution prevention practices that minimize VOC emissions.

      ConocoPhillips is proposing to install a fixed roof on the API separators and DAF vessel, and a vapor collection system to collect and route the emissions from the enclosed vapor space in the API separators and DAF vessel system to a newly installed thermal oxidizer to achieve a 99% destruction efficiency of the collected VOC to demonstrate compliance with the control requirements of this regulation. For the aeration system, ConocoPhillips is proposing pollution prevention practices, including proper operation of upstream wastewater treatment equipment as compliance with the control requirements of ARM 17.8.752 for VOC emissions.

      The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

   b. New Individual Drain System:
      The NCVU project includes the installation of a new individual drain system (IDS) with the construction of the new Crude and Vacuum Units. A search of the EPA RBLC database provides that BACT for emission sources (e.g., process drains, junction boxes) associated with an IDS include water seals, capped or plugged piping, tight seals for access point covers, and closed system and control

device systems.

ConocoPhillips is proposing to comply with 40 CFR Part 60, Subpart QQQ, and NESHAP Subpart FF requirements, which include the above noted control equipment and techniques identified in the RBLC database, dependent upon the type of IDS equipment, as compliance with the control requirements of ARM 17.8.752 for VOC emissions from the new IDS.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

c. Wastewater Treatment System Thermal Oxidizer:
The same type of poor design and operations that contribute to elevated CO emissions from gaseous fuel combustion device contribute to VOC emissions. A review of the EPA RBLC database indicates that proper design and operation represent available VOC emission control technologies for thermal oxidizers combusting gaseous fuels and waste streams. Considering the intent of thermal oxidizers is the destruction of VOC emissions, additional VOC emissions control for such an emissions unit is not practical. ConocoPhillips proposes proper equipment design and operation of the new thermal oxidizer as compliance with the control requirements of ARM 17.8.752 for VOC emissions.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

d. Fugitive Components:
A review of the EPA RBLC database provides that leak detection and repair (LDAR) programs and closed vent systems are the primary methods for controlling fugitive emissions from piping components.

ConocoPhillips proposes compliance with 40 CFR 60, Subpart GGG; 40 CFR 60, Subpart GGGa for the new fugitive emission components associated with the NCVU project; 40 CFR 63, Subpart CC; and the LDAR requirements (500 ppmv leak detection and quarterly monitoring for valves in light liquid/vapor service and 2,000 ppmv leak detection and monthly monitoring for light liquid pumps) included in the Consent Decree that ConocoPhillips entered into with the EPA as compliance with the control requirements of ARM 17.8.752 for VOC emissions from the new piping fugitive components.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

New Cooling Water Tower:

1. PM/PM_{10} Emissions:
Cooling water will be supplied to process operations from a forced-draft, wetted media cooling tower. The unit receives cooling water returned from process operations and circulates the water through a media that provides for contact with the forced air stream through the tower, promoting cooling through evaporation. PM emissions from wet cooling water towers are primarily the result of drift droplets, liquid water droplets entrained in the air stream that are carried out of the tower. Various design and operating factors such as the tower type, tower model, tower

capacity, air velocity, inlet and outlet flow temperatures, and air density determine the amount of drift that escapes the cooling tower. A search of data of the RBLC database indicates that the use of a high efficiency drift eliminator is the only control that has been applied for control of PM emissions from cooling towers, resulting in reported % drift values that range from 0.0005% to 0.005% of recirculating water flow.

The only other available technology for control of PM emissions would be the construction of a dry cooling tower in place of a wet cooling tower. Dry cooling towers do not emit PM; the cooling water return is pumped through a large bank of radiator coils that are cooled by a forced air supply on the outer finned surface of the coils. Since the water remains in a closed system, drift cannot form and PM is not emitted. Dry cooling towers, however, can achieve a maximum cooling of only 25˚F temperature delta from the ambient dry bulb air temperature. Since for the NCVU Project, the difference in temperature between the design cooling water supply temperature and the maximum ambient air temperature exceeds this quantity, a dry cooling tower is not considered to be technically feasible. As a result, it is rejected from further analysis as BACT for control of PM emissions from process cooling water, and the use of a wet cooling tower is required.

ConocoPhillips proposes as BACT the only PM control for wet cooling towers that has been demonstrated, namely equipping the tower with a high efficiency drift eliminator. The BACT emission rate for PM/PM_{10} will correspond to a 0.0005% drift rate, the lowest rate currently demonstrated.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

2. $PM_{2.5}$ Emissions:
   a. Primary:
      Since the cooling tower is a source of PM_{10} emissions, it is potentially a source of direct $PM_{2.5}$ emissions. Samples of emissions from the cooling tower associated with the NCVU project have not been collected to determine the filterable and condensable fractions of PM. Therefore, other sources of data must be relied on to assess the proportion of total PM emissions that are $PM_{2.5}$ and assess possible control options to be considered as BACT.

      The Microelectronics Center of North Carolina Environmental Modeling Center developed the Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System, an emissions processor which contains compilations of emissions inventory data. Emission inventories are typically available with annual total emissions for each emissions source. Models, however, typically require emissions data on an hourly basis for each model species. Emissions processors, such as SMOKE, transform an emission inventory through temporal allocation, chemical speciation, and spatial allocation, to achieve the input requirements of the air quality model.

      In its speciation database, SMOKE indicates that 100% of refinery cooling tower particulate emissions are $PM_{2.5}$, of which over 70% is fine mode PM (as opposed to organic or inorganic aerosol). Therefore, ConocoPhillips will consider the same control options that apply to PM_{10} emissions as also appropriate for $PM_{2.5}$ emissions. ConocoPhillips proposed as BACT for primary $PM_{2.5}$ equipping the wet cooling tower with a high efficiency drift eliminator. Control of drift to

0.0005% of the water recirculation rate will qualify as the BACT emission rate for primary $PM_{2.5}$.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

b. Secondary:
Since the cooling tower is not a source of $PM_{2.5}$ precursors NO_x and SO_2, a BACT analysis for secondary $PM_{2.5}$ emissions is not required.

3. VOC Emissions:
A review of the EPA RBLC database indicates that monitoring, inspection, and maintenance are the most stringent controls for VOC emissions from cooling water towers. ConocoPhillips is proposing to construct a new cooling water tower as part of the NCVU project and proposes to implement a monitoring, inspection, and maintenance plan to comply with the control requirements of this regulation for VOC emissions. This monitoring program will consist of monitoring the free chlorine content in the cooling tower water, bleach additive usage, and olfactory hydrocarbon leak detection measures. Monitoring these parameters will ensure that any exchanger leaks that may occur are identified and repaired in a timely manner.

The Department has determined that the control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

IV. Emission Inventory

The following table summarizes the net emission increases and decreases for each project-affected source:

Emission Point Number	Equipment Number	Project-affected Unit	New, Existing, or Deleted Source	Tons/Year						
				PM/ PM_{10}	SO_2	NO_x	CO	VOC	H_2S	Lead
48	H-2301	Crude Heater	New	5.38	3.90	28.19	7.95	3.90	--	0.0027
49	H-2401	Vacuum Heater	New	1.89	1.37	9.91	2.79	1.37	--	0.0010
2	H-1	Small Crude Unit Heater	Deleted	-0.99	-0.24	-2.02	-0.19	-0.72	--	-0.0005
21	H-24	Large Crude Unit Heater	Deleted	-2.96	-0.71	-38.95	-32.72	-2.14	--	-0.0016
14	H-17	Vacuum Heater	Deleted	-1.17	-0.28	-15.35	-12.89	-0.84	--	-0.0006
41	H-9501	No. 5 HDS Charge Heater	Existing	0.49	1.95	2.61	14.34	0.36	--	0.0002
42	H-9502	No. 5 HDS Stabilizer Reboiler Heater	Existing	0.62	3.76	4.87	11.69	0.45	--	0.0002
33	H-8401	No. 4 HDS	Existing	0.11	2.35	1.82	2.20	0.46	--	0.0001
34	H-8402	No. 4 HDS	Existing	0.00	2.34	1.17	0.91	0.41	--	0.0000
22		FCCU Stack	Existing	0.00	5.61	0.00	47.44	--	--	0.0060
13	H-16	Stabilizer Reboiler, Sat Gas	Existing	0.14	1.77	1.78	1.50	0.10	--	0.0001

17	H-20	Butamer	Existing	0.05	0.26	0.65	0.54	0.04	--	0.0000
18	H-21	Alky	Existing	0.16	3.53	2.05	1.72	0.11	--	0.0000
35	H-9401	No. 1 H_2 Heater	Existing	3.80	1.71	16.11	0.00	0.18	--	0.0017
43	H-9701	No. 2 H_2 Reformer Heater	Existing	2.50	1.98	14.89	7.78	0.84	--	0.0036
50	--	Wastewater Treatment System Thermal Oxidizer	New	0.05	0.039	0.48	0.29	0.09	--	--
--	1102	Heavy Sour Crude Tank	Existing	--	--	--	--	0.00	--	--
24	--	Facility Wide Tank Emissions	Existing	--	--	--	--	7.51	--	--
26	--	Old Lrg/Sm Crude and Vacuum Jnit Fugitive Component Emissions	Deleted	--	--	--	--	-14.09	--	--
26	--	New Crude and Vacuum Unit Fugitive Component Emissions	New	--	--	--	--	13.57	--	--
26	--	Modified Unit Fugitive Component Emissions	New	--	--	--	--	1.23	--	--
26	CWT-2501	New Cooling Water Tower	New	1.32	--	--	--	1.84	--	--
36	--	Coke Handling	Existing	0.00	--	--	--	--	--	2E-07
1	S-101/ S-401	Jupiter Sulfur Recovery Unit	Existing	22.33	77.34	56.35	0.00	--	--	--
26	--	Wastewater Treatment System Fugitive Emissions	New	--	--	--	--	3.65	--	--
--	--	Sulfur Loading	Existing	--	--	--	--	--	0.13	--
TOTALS				**33.73**	**106.69**	**84.56**	**53.34**	**18.31**	**0.13**	**0.01**

The full emission inventory is contained in Permit Application #2619-24. The PSD netting summary is also in Section II.G of this permit analysis.

V. Existing Air Quality

ConocoPhillips is located at 401 South 23rd Street in Billings, Montana in the NW ¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County. This area is considered attainment for all criteria pollutants. The Billings CO nonattainment area, which included ConocoPhillips, was reclassified to attainment by EPA's direct final rulemaking on April 22, 2002. The Laurel SO_2 nonattainment area is nearby.

VI. Ambient Air Impact Analysis

ConocoPhillips contracted with Environ International Corporation (Environ) to conduct air quality modeling for the proposed NCVU Project as part of the ConocoPhillips air quality permit

application. This air quality modeling was conducted, pursuant to the requirements of ARM 17.8.820 and ARM 17.8.1106, to demonstrate that the proposed modification would not cause or contribute to a violation of any NAAQS or any applicable PSD increment (Class II Analysis) or cause or contribute to any adverse impact on visibility within any mandatory federal Class I areas (Class I Analysis).

Class II Analysis

The NCVU Project is above the significant levels listed in ARM 17.8.801(27) for NO_x, SO_2, and PM/PM_{10}. Therefore, ConocoPhillips is required to demonstrate compliance with the NAAQS and applicable PSD increments for these pollutants.

The EPA-approved American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) Version 07026 model and 5 years of meteorological data (2001-2005) were utilized for this modeling demonstration. The surface data was collected at the Billings/Logan International Airport (station #24033), and the upper air data was collected at the Great Falls National Weather Service Station (station #24143). The receptor points comprised three Cartesian grids, as well as discrete, individual receptor points. Discrete receptors were placed approximately 100 m apart along the facility fence line. A fine Cartesian grid encompassed receptor points every 100 m from the fence line to 1 km. A medium receptor grid included receptors spaced at 250 m intervals from 1 km to 3 km. A coarse receptor grid was represented by receptors spaced at 500 m intervals from 3 km to 10 km. This total receptor set contained 3,661 receptors, which was used for the NO_x and PM_{10} analyses. For the SO_2 modeling, the coarse receptor grid was extended to 15 km for a total of 5,781 receptors. The receptor grid elevations were derived from 72 digital elevation model (DEM) files using the United States Geological Survey (USGS) digitalized topographic maps, North American Datum 1983. Building downwash was calculated using the EPA Building Profile Input Program (BPIP) PRIME. Building parameters for 146 buildings, including building location, length, width, and height were utilized in the BPIP-PRIME model.

The air quality impact analysis was performed in two phases: a significant analysis and a full impact analysis. First, a PSD significance analysis was conducted to evaluate whether the net emissions increase in NO_x, SO_2, and PM/PM_{10} have a modeled maximum impact on the surrounding region that would exceed the PSD modeling significance levels shown in Table VI-1 below. If the maximum estimated off-site concentration exceeds the PSD modeling significant level for any time period or pollutant, then a full impact analysis is required for that pollutant and averaging period to determine compliance with the NAAQS and PSD Increments. If required, the full impact analysis must include the proposed new emissions, as well as all other sources in the area, including increment-consuming sources.

Table VI-1 Applicable PSD Air Quality Standards

Pollutant	Averaging Period	PSD Modeling Class II Significance Level ($\mu g/m^3$)	Preconstruction Monitoring Exemption Level ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	MAAQS ($\mu g/m^3$)
NO_x	1-hour	-	-	-	-	564
	Annual	1	14	25	100	94
SO_2	1-hour	25	-	-	-	1,300
	3-hour	25	-	512	1,300	-
	24-hour	5	13	91	365	262
	Annual	1	-	20	80	52
PM_{10}	24-hour	5	10	30	150	150
	Annual	1	-	17	-	50

The significance modeling demonstrated that the project-related emissions changes at the facility would have a significant impact for SO_2. PM_{10} and NO_x impacts were below their respective significance levels and no further analysis was performed for these pollutants. Table VI-2 below summarizes the significance modeling results.

Table VI-2. Summary of Significance AERMOD Modeling Results

Pollutant	Ave. Period	Met. Year	Modeling Sig. Level ($\mu g/m^3$)	Max. Concentration ($\mu g/m^3$)[2]	Distance to Furthest Sig. Receptor (km)	Radius of Impact (km)	Receptor with Max. Impact			Met. Data Period (yymmddhh)
							UTM_x (m)	UTM_y (m)	Elevation (m)	
NO_x[1]	Annual	2001	1	0.76	N/A	N/A	695,460	5,073,133	946	Annual
NO_x[1]	Annual	2002	1	0.79	N/A					
NO_x[1]	Annual	2003	1	0.74	N/A					
NO_x[1]	Annual	2004	1	0.80	N/A					
NO_x[1]	Annual	2005	1	0.85	N/A					
PM_{10}	Annual	2001	1	0.27	N/A	N/A	696,440	5,073,326	1,018	Annual
PM_{10}	Annual	2002	1	0.32	N/A					
PM_{10}	Annual	2003	1	0.28	N/A					
PM_{10}	Annual	2004	1	0.26	N/A					
PM_{10}	Annual	2005	1	0.29	N/A					
PM_{10}	24-hour	2001	5	4.42	N/A		696,240	5,072,626	1,025	04110724
PM_{10}	24-hour	2002	5	3.40	N/A					
PM_{10}	24-hour	2003	5	4.50	N/A					
PM_{10}	24-hour	2004	5	4.92	N/A					
PM_{10}	24-hour	2005	5	3.86	N/A					
SO_2	Annual	2001	1	1.26	1	17	695,460	5,073,133	946	Annual
SO_2	Annual	2002	1	1.38	2					
SO_2	Annual	2003	1	1.31	1					
SO_2	Annual	2004	1	1.32	1					
SO_2	Annual	2005	1	1.45	1					
SO_2	24-hour	2001	5	14.71	9		696,240	5,072,626	1,025	04110724
SO_2	24-hour	2002	5	12.43	5					
SO_2	24-hour	2003	5	16.17	9					
SO_2	24-hour	2004	5	16.31	3					
SO_2	24-hour	2005	5	12.99	7					
SO_2	3-hour	2001	25	103.69	7		696,640	5,071,826	1,039	01110124
SO_2	3-hour	2002	25	95.19	7					
SO_2	3-hour	2003	25	100.08	7					
SO_2	3-hour	2004	25	82.86	7					
SO_2	3-hour	2005	25	99.13	7					
SO_2	1-hour	2001	25	272.09	15		696,440	5,072,826	1,030	03052303
SO_2	1-hour	2002	25	285.55	15					
SO_2	1-hour	2003	25	300.19	15					
SO_2	1-hour	2004	25	248.57	17					
SO_2	1-hour	2005	25	297.34	15					

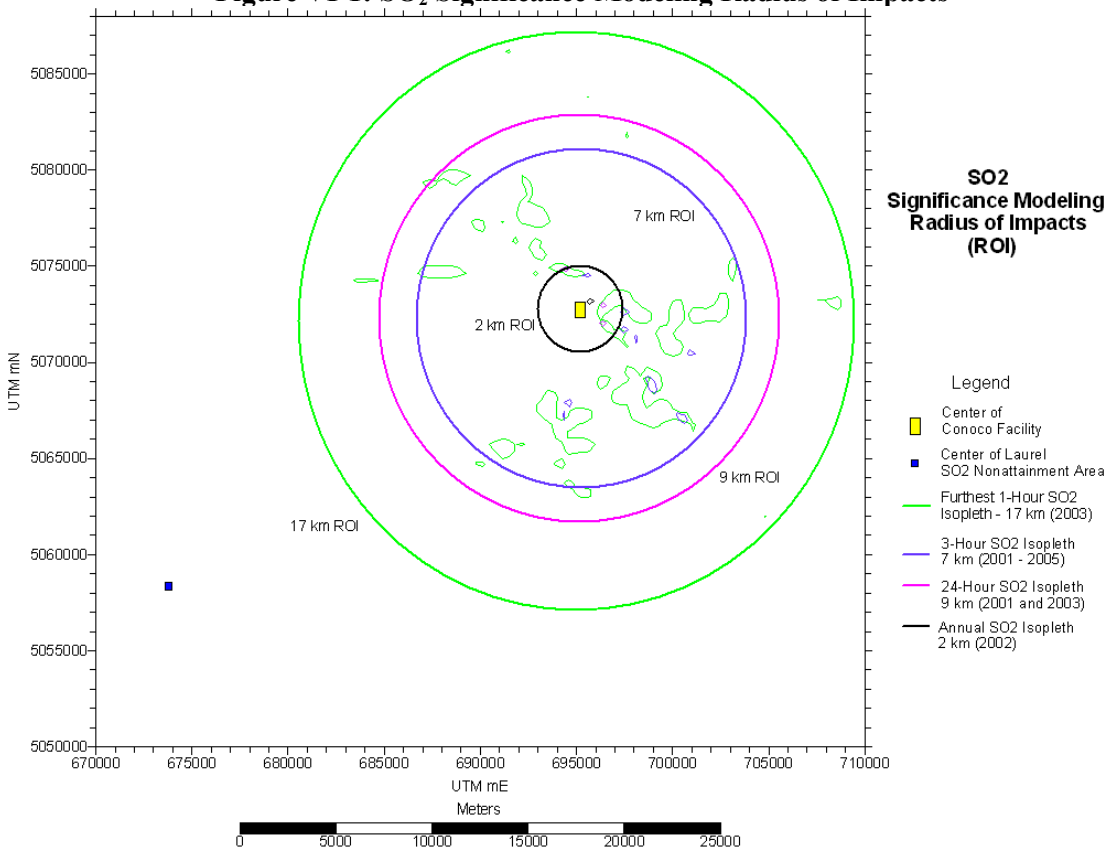
[1] Includes use of the Ambient Ratio Method for the NO_x to NO_2 conversion (0.75).
[2] Maximum concentrations indicate the highest-first-high concentrations for all averaging periods for comparison to the significance levels.

The results of the significance modeling show that NO_x and PM_{10} were below their respective preconstruction monitoring exemption listed in Table VI-1. The maximum modeled SO_2 concentration, however, exceeded its preconstruction monitoring exemption level of 13 $\mu g/m^3$ for the 24-hour averaging period. Preconstruction monitoring is used to determine the effect emissions from a proposed project may have on air quality in the area. The Department provided monitoring data to Environ to fulfill this PSD preconstruction monitoring requirement. The Department's Coburn Road (AIRS #30-111-0066) SO_2 monitoring site was selected as representative of the air quality in the area, which is about 2 km from the facility. For this requirement, the 2007 data was reviewed and there were no exceedances of the SO_2 NAAQS/MAAQS. The maximum monitored values were 266 $\mu g/m^3$, 130 $\mu g/m^3$, and 51 $\mu g/m^3$ for the 1-, 3-, and 24-hour averaging periods, respectively.

A PSD increment analysis was conducted in order to demonstrate compliance with the SO_2 PSD Class II increments specified in ARM 17.8.804. Yellowstone Energy Limited Partnership's (formerly Billings Generation Inc.) initial PSD permit states, "As a result of this first PSD application for the Billings area, the minor source baseline date is now triggered for particulates, SO_2 and NO_x. The PSD application was deemed complete on November 8, 1991." The Department has reviewed this initial PSD permit, as well as the corresponding permit application, and has determined that this statement is incorrect. Yellowstone Energy Limited Partnership was a new source under its initial PSD permit application and was considered a major source of NO_x emissions. It was not, however, considered a major source for either SO_2 or particulates; therefore, these pollutants were not subject to PSD and the minor source baseline date for SO_2 or particulates has not yet been established in the Billings area. In accordance with ARM 17.8.801(3), the Department interprets the baseline area in which the minor source baseline date is established to be the intrastate area designated as attainment or unclassifiable in 40 CFR 81.327 in which the source establishing the minor source baseline date would have an air quality impact equal to or greater than 1 $\mu g/m^3$ (annual average). Therefore, there are no other PSD sources in the area that have established the minor source baseline date for SO_2. Since the SO_2 minor source baseline date has not yet been established, the only emissions that consume/expand increment are the actual emissions resulting from construction-related changes at major stationary sources since the major source baseline date. The major source baseline date for SO_2 is specified in ARM 17.8.801(21) as January 6, 1975.

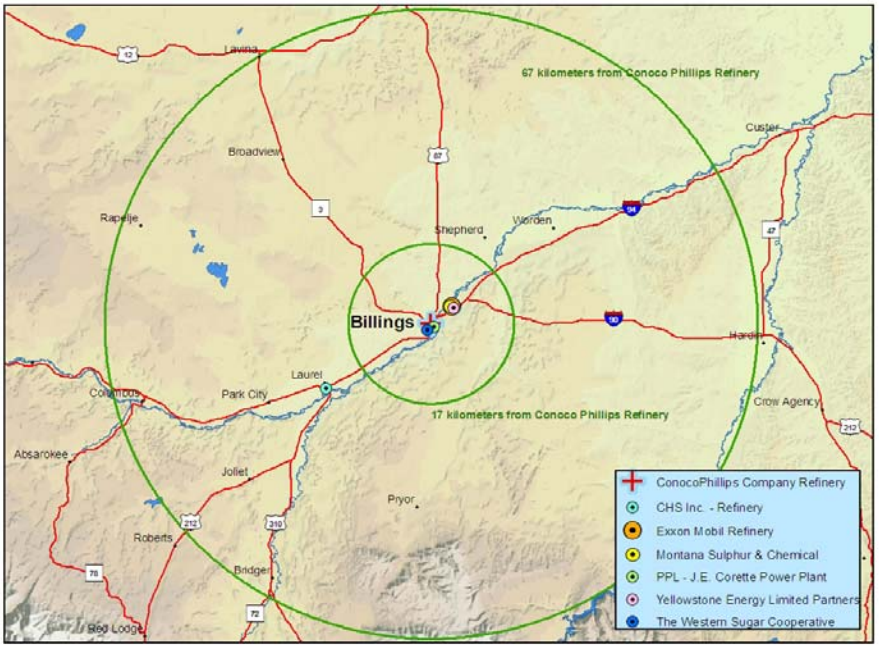
The increment analysis conducted for the NCVU project included all of the construction-related changes at the ConocoPhillips refinery, as well as all of the construction-related changes for other major stationary sources located within radius of impact plus 50 km. Figure VI-1 shows the radius of impacts for each of the SO_2 averaging periods. As shown, the furthest radius of impact occured at 17 km for the 1-hour SO_2 MAAQS.

Figure VI-1: SO_2 Significance Modeling Radius of Impacts



Seven major stationary sources were identified within the maximum radius of impact of 17 km plus 50 km. These sources included: ConocoPhillips Company – Billings Refinery, CHS Inc. – Laurel Refinery, ExxonMobil – Billings Refinery, Montana Sulphur and Chemical, PPL – J.E. Corette Power Plant, the Western Sugar Cooperative, and Yellowstone Energy Limited Partnership. These sources are shown below in Figure VI-2.

Figure VI-2: Major Sources Within 17 km ROI + 50 km



A detailed increment inventory for the identified sources was not available from the Department; as such, Environ conducted an extensive review of the Department's records for the emissions and construction histories for each of these sources. Due to the difficulty in determining the actual emission changes associated with each construction-related activity, Environ elected instead to perform a conservative analysis of the emissions changes since the major source baseline date by comparing current actual emissions to 1975 "baseline" emissions. Environ used an average of 2005 and 2006 emissions to determine actual emissions, except for project-affected sources, in which case the post-project PTE emissions were used. It was assumed that only emission changes which would consume increment and emissions changes where expansion of increment could be readily documented would be included in the model. Those emission changes which would appear to expand increment (and could not be readily documented) would have their emissions in the "baseline" year set equal to zero, which had the effect of turning an apparent expansion of increment into a consumption of increment. However, for three large sources of SO_2: the ExxonMobil FCCU, the Montana Sulphur Claus Units, and the PPL – J.E. Corette Stack, Environ instead chose to set the baseline emissions equal to the current average actual emissions, which in effect shows no expansion or consumption of increment. However, after reviewing the construction histories submitted by Environ for each of these three sources, the Department determined that there has been some construction-related activities involving that ExxonMobil FCCU since the major source baseline date that have consumed increment. As such, the Department re-ran the increment model using the PTE for each of these construction-related activities to ensure that no SO_2 PSD increment violation occurred. The results of the Department's model, shown below in Table VI-3, show no violation of the SO_2 PSD increment.

Table VI-3. PSD Increment AERMOD Modeling Results.

Pollutant	Ave. Period	Met. Year	PSD Class II Increment (µg/m³)	Maximum Concentration (µg/m³)	Percent of Increment Consumption (%)	Receptor Location UTM (NAD83)			Met. Period (yymmddhh)
						Easting (mE)	Northing (mN)	Elev. (m)	
SO_2	3-Hour	2001	512	153	29.9	697,140	5,072,476	1,061	05121609
		2002	512	138	26.9				
		2003	512	149	29.1				
		2004	512	149	29.1				
		2005	512	157	30.6				
	24-Hour	2001	91	29	32.2	696,640	5,072,526	1,063	01080524
		2002	91	23	25.1				
		2003	91	25	27.3				
		2004	91	28	30.9				
		2005	91	28	31.2				
	Annual	2001	20	2.5	12.5	696,540	5,073,326	1,025	Annual
		2002	20	2.7	13.5				
		2003	20	2.4	12.0				
		2004	20	2.4	12.0				
		2005	20	2.1	10.5				

In order to demonstrate compliance with the SO_2 NAAQS, Environ reviewed the Billings SO_2 SIP and associated emissions limits and demonstrated that ConocoPhillips' contribution of SO_2 emissions has not significantly changed as a result of the NCVU project. As part of the Billings SO_2 SIP modeling effort, emissions limits for all major sources were established to ensure compliance with the SO_2 NAAQS. Potential emissions of SO_2 will not change as a result of the NCVU project. New sources and existing sources with an increase in individual potential emissions are being incorporated into the facility emission caps that were developed as part of the Billings SO_2 SIP. These caps are not proposed to be revised as part of this permitting action. Therefore, compliance with the NAAQS as demonstrated through the SIP modeling effort has not

changed.

Environ also conducted an additional impact analysis, in accordance with ARM 17.8.824, to determine local visibility impacts that would occur as a result of this project. The EPA guideline for visibility impairment was applied in this analysis. The EPA VISCREEN (version 1.01) was used to estimate a Level-I analysis of the NCVU project. This model conservatively evaluates whether a plume from a facility is perceptible to an observer under worst-case meteorological conditions for a known distance. Several angles between the observer's line of sight and the sun's radiation (θ) are considered. Two screening criteria are used to carry out the analysis and if either criterion is exceeded, more comprehensive analysis should be carried out. The first criterion, delta E, known as the plume perceptibility parameter, is based on the difference in color and brightness between the plume and the background. The second criterion is called the green contrast value (C_p). C_p is defined as the contrast of a plume against a viewing background such as the sky or a terrain feature. The results of the VISCREEN model, as shown below in Table VI-4, show no exceedences of delta E or C_p. Therefore, the proposed project would not significantly impair the local visibility.

Table VI-4 Level I VISCREEN Results

Level I Input Parameter	θ	Source-Observer Distance (km)	Delta E		C_p	
			Critical	Plume	Critical	Plume
Sky	10	25	2.0	0.378	0.05	0.002
Sky	140	25	2.0	0.103	0.05	-0.002
Terrain	10	25	2.0	0.181	0.05	0.002
Terrain	140	25	2.0	0.035	0.05	0.002

Class I Analysis

To demonstrate compliance with ARM 17.8.1106, Environ conducted modeling to demonstrate the change in emissions resulting from the NCVU project would not cause or contribute to adverse impacts on visibility within any mandatory federal Class I area. Additional analyses were completed to determine impacts on air quality related values. There are four mandatory federal Class I areas and one non-mandatory Class I area within the area of interest: Gates of the Mountains Wilderness Area (mandatory), UL Bend Wilderness Area (mandatory), North Absaroka Wilderness Area (mandatory), Yellowstone National Park (mandatory) and Northern Cheyenne Indian Reservation (non-mandatory). The distances from the proposed project to the nearest receptor in the Class I Areas are summarized in Table VI-5 below:

Table VI-5: Nearest Distance to Class I Area from Proposed Project

ID	Class I Area	Distance (km)
GAMO	Gates of the Mountains Wilderness Area	415
ULBEWILD	UL Bend Wilderness Area	204
NOAB2	North Absaroka Wilderness Area	155
YELL4	Yellowstone National Park	184
NCIR	Northern Cheyenne Indian Reservation	184

In addition to the Class I areas listed above, Environ also evaluated impacts from the NCVU project at two sensitive Class II areas at the request of the USDA Forest Service. These areas included the Absaroka Beartooth Wilderness – Stepping Stone Lake and the Absaroka Beartooth Wilderness – Twin Island Lake. The USDA Forest Service requested that both visibility and acid deposition impacts at these two sensitive Class II areas be evaluated.

The EPA-approved CALPUFF version 5.8 model and 3 years of meteorological data (2001-2003) were used for this analysis. CALPUFF is a long-range pollutant transport model. The National

Park Service provided the receptor sets for the mandatory Class I areas, the Department provided the receptor set for the non-mandatory Class I area (the Northern Cheyenne Indian Reservation), and the USDA Forest Service provided the receptor locations for the two sensitive Class II lakes. The CALPUFF model requires background ozone data for the empirical chemistry module and background ammonia data for calculating $SO_4/NO_3/NH_4$ equilibrium. Day-specific hourly ozone data from sites within the modeling domain were used. Additionally, monthly values of 30 ppb were utilized for October through May and monthly values of 50 ppb were utilized for June through September, as specified by the Department.

Class I PSD Increments for SO_2, NO_x and PM_{10} are specified in ARM 17.8.804. The cumulative air quality impacts of all new sources are required to be below the PSD Class I increments. In 1996, EPA published a Federal Register notice of proposed Class I area significant impact level (SIL) thresholds for single projects. These proposed single-project SILs are defined as being approximately 4% of the PSD Class I area increment. If a project's impact is below the Class I area proposed single-project SIL, then its impact is considered insignificant. If project's estimated impact exceeds the Class I area allowable PSD concentration increments, then the project must perform mitigation to achieve impacts below the PSD increments. If estimated concentrations at Class I areas exceed the proposed single-source SIL, then a full impact analysis must be performed. As shown in Table VI-6 below, the estimated air quality impacts at the five Class I areas and two sensitive Class II areas from the NCVU project will not exceed any proposed single-source SIL or any applicable Class I area PSD Increment; therefore, the impacts from this project on Class I and II areas are considered insignificant.

Table VI-6: CALPUFF Estimated PSD Pollutant Concentration Impacts at Class I and Selected Class II Areas

Pollutant – Averaging Period	Class I Area Thresholds ($\mu g/m^3$)		Class I and II Areas ($\mu g/m^3$)						
	Proposed SIL	Allowable Class I Areas PSD Increments	Stepping Stone Lake[1]	Twin Island[1]	Gates of the Mountains	North Absaroka	UL Bend	Yellowstone	Northern Cheyenne Indian Reservation
2001									
NO_2 – Annual	0.1	2.5	0.00007	0.00007	0.00001	0.00013	0.00010	0.00005	0.00032
SO_2 – 3-hour	1.0	25	0.04325	0.04196	0.00945	0.05633	0.04265	0.03694	0.06021
SO_2 – 24-hour	0.2	5	0.01921	0.01943	0.00344	0.01547	0.01526	0.01545	0.01263
SO_2 – Annual	0.1	2	0.00039	0.00037	0.00012	0.00057	0.00082	0.00025	0.00141
PM_{10} – 24-hour	0.3	8	0.01230	0.01262	0.00398	0.01354	0.01139	0.01055	0.00967
PM_{10} - Annual	0.2	4	0.00027	0.00027	0.00011	0.00042	0.00062	0.00019	0.00079
2002									
NO_2 – Annual	0.1	2.5	0.00005	0.00005	0.00001	0.00012	0.00004	0.00004	0.00032
SO_2 – 3-hour	1.0	25	0.04040	0.03659	0.01309	0.04998	0.02563	0.02842	0.05246
SO_2 – 24-hour	0.2	5	0.01136	0.01100	0.00469	0.01832	0.00596	0.00813	0.01033
SO_2 – Annual	0.1	2	0.00044	0.00042	0.00015	0.00068	0.00040	0.00028	0.00139
PM_{10} – 24-hour	0.3	8	0.00604	0.00590	0.00694	0.01426	0.00542	0.00545	0.00939
PM_{10} - Annual	0.2	4	0.00029	0.00029	0.00017	0.00044	0.00034	0.00021	0.00083
2003									
NO_2 – Annual	0.1	2.5	0.00004	0.00004	0.00001	0.00010	0.00006	0.00002	0.00033
SO_2 – 3-hour	1.0	25	0.01797	0.01949	0.00884	0.04925	0.03457	0.01815	0.04024
SO_2 – 24-hour	0.2	5	0.00663	0.00618	0.00497	0.01052	0.00978	0.00505	0.01095
SO_2 – Annual	0.1	2	0.00034	0.00033	0.00010	0.00055	0.00061	0.00020	0.00133
PM_{10} – 24-hour	0.3	8	0.00652	0.00674	0.00703	0.00597	0.01074	0.00352	0.00735
PM_{10} - Annual	0.2	4	0.00026	0.00025	0.00009	0.00036	0.00053	0.00016	0.00074

[1] Stepping Stone Lake and Twin Island Lake are located within the Absaroka Beartooth Wilderness Area, which is a Class II Area. Although these lakes are not part of a Class I area, NO_2, SO_2, and PM_{10} concentrations are presented for informational purposes only.

The Federal Land Managers have also developed threshold levels for visibility and sulfur and nitrogen deposition at Class I areas. The estimated visibility impacts at the four mandatory Class I areas and the two sensitive Class II areas evaluated are below the 5% light extinction threshold, as shown in Table VI-7 below. According to the Federal Land Managers' Air Quality Related Values Workgroup, Phase 1 Report, December 2000, Federal Land Managers are not likely to object to the issuance of a PSD permit on visibility impacts if the maximum change in light extinction is below 5%. Therefore, no adverse visibility impacts are anticipated at any Class I area.

Table VI-7:
CALPUFF Estimated Visibility Impacts at Class I and Class II Areas

	# Days > 5%	# Days > 10%	Max Change (%)
Gates of the Mountains			
2001	0	0	0.36
2002	0	0	0.64
2003	0	0	0.80
North Absaroka			
2001	0	0	3.49
2002	0	0	2.69
2003	0	0	1.32
Yellowstone			
2001	0	0	1.54
2002	0	0	1.14
2003	0	0	0.76
UL Bend			
2001	0	0	3.37
2002	0	0	0.90
2003	0	0	1.74
Absaroka Beartooth, Stepping Stone			
2001	0	0	1.47
2002	0	0	1.57
2003	0	0	1.36
Absaroka Beartooth, Twin Island			
2001	0	0	1.54
2002	0	0	1.50
2003	0	0	1.40

Class I Area deposition impacts were also considered. Acid deposition impacts are represented by total sulfur and total nitrogen deposition. The USDA Forest Service has developed nitrogen and sulfur deposition thresholds for these pollutants. Although these values vary for different locations, the lowest "green line" nitrogen and sulfur deposition values are 3 kilograms per hectare per year (kg/ha-yr). The National Park Service has also established nitrogen and sulfur deposition thresholds of 0.005 kg/ha-yr. The maximum annual total nitrogen and sulfur deposition rates due to the proposed project at any Class I area receptors were estimated to be 0.00013 and 0.00088 kg/ha-yr, respectively. These rates occurred at the Northern Cheyenne Indian Reservation for 2003 and 2002 meteorological years, respectively.

In addition to the Class I area deposition impacts addressed above, Environ also provided an analysis of acid deposition impacts at the two sensitive Class II lakes: Absaroka Beartooth - Stepping Stone and Absaroka Beartooth - Twin Island. For the two sensitive lakes, the USDA Forest Service requested that the Acid Neutralizing Capacity (ANC) screening protocol for lakes

being used. The USDA Forest Service's Limits of Acceptable Change lists the ANC limit change as 10% from baseline. This percentage change is applicable to accumulative analysis, but since the Absaroka Beartooth Wilderness is not a Class I area, the Forest Service did not request an accumulative analysis be performed. The maximum change in the ANC was determined to be 0.03% in 2002 for both Stepping Stone and Twin Island Lakes. Therefore, no adverse deposition impacts to Class I or II areas are expected to occur as a result of the NCVU project.

VII. Human Health Risk Assessment

In accordance with 75-2-215, MCA, the Department may not issue a permit to a facility until: (d) the Department has reached a determination that the projected emissions and ambient concentrations will constitute a negligible risk to the public health, safety, and welfare and to the environment.

A health risk analysis to estimate the risk of burning HAPs in the new wastewater treatment system thermal oxidizer was completed as part of this permit application. The health risk analysis contained the HAPs from the 1990 Federal Clean Air Act Amendments with an established risk value. The ambient concentrations were determined using SCREEN3, an EPA-approved screening model. The indicated inputs are design parameters that were obtained from the vendor. Both building downwash and complex terrain were accounted for in the SCREEN3 analysis. The major geological feature in the vicinity of the refinery is Sacrifice Cliff. To ensure that the most conservative results were modeled, SCREEN3 was run two times: once with the receptors placed along a line to Sacrifice Cliff directly east of the facility (shortest distance) and once with the receptors placed along a line to the point on Sacrifice Cliff with the highest elevation (highest point). The individual 1-hour results for each pollutant were then calculated by multiplying the highest modeled impact of 1.123 $\mu g/m^3$ by the percentage of each individual HAP making up the total of the HAP emissions. HAPs associated with combustion of natural gas/RFG and the non-destructed portion of the vent gas to the thermal oxidizer were considered. The maximum 1-hour concentrations were then converted to an annual average and used in the health risk assessment.

```
WWTS Thermal Oxidizer: SCREEN3 Model Run

    Complex Terrain Inputs:
        Source Type                          =        POINT
        Emission Rate (G/S)                  =        0.170E-02
```

```
    Stack Height (M)                        =       6.10
    Stack Diameter (M)                      =       0.381
    Stack Exit Velocity (M/S)               =       8.75
    Stack Gas Exit Temp (K)                 =       1033.00
    Ambient Air Temp (K)                    =       293.00
    Receptor Height (M)                     =       0.0000
    Urban/Rural Option                      =       RURAL

Simple Terrain Inputs:
    Source Type                             =       POINT
    Emission Rate (G/S)                     =       0.170E-02
    Stack Height (M)                        =       6.10
    Stack Diameter (M)                      =       0.381
    Stack Exit Velocity (M/S)               =       8.75
    Stack Gas Exit Temp (K)                 =       1033.00
    Ambient Air Temp (K)                    =       293.00
    Receptor Height (M)                     =       0.0000
    Urban/Rural Option                      =       RURAL
    Building Height (M)                     =       14.63
    Min Horiz Bldg Dim (M)                  =       52.40
    Max Horiz Bldg Dim (M)                  =       52.40
```

Table VII-1: Summary of SCREEN3 Model Results – Shortest Distance

Calculation Procedure	Maximum 1 Hour Concentration ($\mu g/m^3$)	Distance of Maximum (M)	Terrain Height (M)
Simple Terrain	1.066	291	0
Complex Terrain	1.809E-02	1000	57

Table VII-2: Summary of SCREEN3 Model Results – Highest Point

Calculation Procedure	Maximum 1 Hour Concentration ($\mu g/m^3$)	Distance of Maximum (M)	Terrain Height (M)
Simple Terrain	1.123	265	0
Complex Terrain	1.447E-02	1184	42

The SCREEN3 model determined that, with the exception of benzene and total chromium, a health risk assessment was not necessary because the HAP concentrations in Table VII-3 below were less than the levels contained in ARM 17.8.770(1)(c)(ii).

Table VII-3. Health Risk Assessment HAP Concentrations

Pollutant	**Modeled Level ($\mu g/m^3$)**	**Cancer Deminimis Level ($\mu g/m^3$)**	**Non-Cancer Chronic Deminimis Level ($\mu g/m^3$)**	**Non-Cancer Acute Deminimis Level ($\mu g/m^3$)**
Benzene	**2.2E-02**	1.20E-02	7.10E-01	N/A
Cresols (mixed isomers)	1.0E-06	N/A	1.80E+00	N/A
Cumene	1.1E-03	N/A	N/A	N/A
Ethylbenzene	4.0E-03	N/A	1.00E+01	N/A
Hexane(N-)	2.7E-02	N/A	2.00E+00	N/A

Methanol	2.2E-04	N/A	6.20E+00	N/A
Napthalene	4.2E-04	N/A	1.40E-01	N/A
Phenol	8.1E-07	N/A	4.50E-01	N/A
Toluene	3.3E-02	N/A	4.00E+00	N/A
Xylenes (mixed isomers)	2.4E-02	N/A	3.00E+00	4.40E+01
2-Methylnaphthalene	3.0E-07	N/A	N/A	N/A
3-Methylchloranthrene	2.3E-08	N/A	N/A	N/A
7,12-Dimethylbenz(a)anthracene	2.0E-07	N/A	N/A	N/A
Acenaphthene	2.3E-08	N/A	N/A	N/A
Acenaphthylene	2.3E-08	N/A	N/A	N/A
Anthracene	3.0E-08	N/A	N/A	N/A
Benz(a)anthracene	2.3E-08	5.88E-05	N/A	N/A
Benzo(a)pyrene	1.5E-08	5.88E-05	N/A	N/A
Benzo(b)fluoranthene	2.3E-08	5.88E-05	N/A	N/A
Benzo(g,h,i)perylene	1.5E-08	N/A	N/A	N/A
Benzo(k)fluoranthene	2.3E-08	5.88E-05	N/A	N/A
Chrysene	2.3E-08	N/A	N/A	N/A
Dibenzo(a,h)anthracene	1.5E-08	5.88E-05	N/A	N/A
Dichlorobenzene	1.5E-05	9.09E-03	8.00E+00	N/A
Fluoranthene	3.8E-08	N/A	N/A	N/A
Fluorene	3.5E-08	N/A	N/A	N/A
Formaldehyde	9.4E-04	7.69E-03	3.60E-02	3.70E+00
Indeno(1,2,3,c,d)pyrene	2.3E-08	5.88E-05	N/A	N/A
Phenanthrene	2.1E-07	N/A	N/A	N/A
Pyrene	6.3E-08	N/A	N/A	N/A
Arsenic	2.5E-06	2.33E-05	5.00E-03	N/A
Beryllium	1.5E-07	4.17E-05	4.80E-05	N/A
Cadmium	1.4E-05	5.56E-05	3.50E-02	N/A
Chromium, total	**1.8E-05**	8.33E-06	2.00E-05	N/A
Cobalt	1.1E-06	N/A	N/A	N/A
Lead	6.3E-06	N/A	1.50E-02	N/A
Manganese	4.8E-06	N/A	5.00E-04	N/A
Mercury	3.3E-06	N/A	3.00E-03	3.00E-01
Nickel	2.6E-05	3.85E-04	2.40E-03	1.00E-02
Selenium	3.0E-07	N/A	5.00E-03	2.00E-02

Since the modeled levels of benzene and total chromium were above the established de minimis levels summarized in Table VII-3 above, a health risk assessment for these pollutants was conducted to determine if the proposed wastewater treatment system thermal oxidizer complies with the negligible risk requirements of MCA 75-5-215. Since the concerned HAPs are not expected to accumulate in the soil or surface water, only exposure occurring through inhalation was assessed. Only those HAPs for which there are established de minimis levels were evaluated. According to EPA's *Prioritized Chronic Dose-Response Values for Screening Risk Assessments*, there is inadequate information to determine the carcinogenicity of chromium (III) compounds. Available references were reviewed for emissions data of chromium (VI) compounds. The most applicable reference found was for combustion of fuel gas and natural gas in turbines where chromium (VI) compounds were tested and found to be non-detect. Therefore, only benzene was considered in the health risk assessment. The health risk assessment, shown in Table VII-4 below, demonstrated that the installation and operation of the wastewater treatment system thermal oxidizer is in compliance with the requirement to demonstrate negligible risk to human health and the environment.

Table VII-4. Negligible Risk Assessment

Pollutant	Modeled Level ($\mu g/m^3$)	Cancer URF(2) $(\mu g/m^3)^{-1}$	Cancer Risk(3)
Benzene	2.2E-02	7.80E-06	1.73E-07
TOTAL RISK			1.73E-07

(1) Source of chronic dose-response values is from Table 1: Prioritized Chronic Dose-Response Values for Screening Risk Assessments (6/12/07), from www.epa.gov/ttn/atw/toxsource/table1.pdf.
(2) Cancer Chronic Inhalation Unit Risk Factor, units 1/µg/m3
(3) Cancer Risk is unitless and is calculated by multiplying the predicted concentration by the URF.

As documented in the above table and in accordance with the negligible risk requirement, no single HAP concentration results in Cancer Risk greater than 1.00E-06 and the sum of all HAPs results in a Cancer Risk of less than 1.00E-05. Further, the sum of the Chronic Noncancer Reference Exposure Level (CNCREL) hazard quotient is 0, which is less than 1.0 as required to demonstrate compliance with the negligible risk requirement.

VIII. Taking or Damaging Implication Analysis

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?
		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.

IX. Environmental Assessment

An environmental assessment, required by the Montana Environmental Policy Act, was completed for this project. A copy is attached.

DEPARTMENT OF ENVIRONMENTAL QUALITY
Permitting and Compliance Division
Air Resources Management Bureau
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FINAL ENVIRONMENTAL ASSESSMENT (EA)

Issued To: ConocoPhillips Company – Billings Refinery

Air Quality Permit Number: 2619-24

Preliminary Determination Issued: September 24, 2008
Department Decision Issued: November 3, 2008
Permit Final:

1. *Legal Description of Site*: ConocoPhillips operates a petroleum refinery located at 401 South 23rd Street, Billings, Montana, in the NW¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County. Jupiter operates a sulfur recovery facility, within the petroleum refinery area described above, at 2201 7th Avenue South, Billings, Montana. The Jupiter facility is operated as a joint venture, of which ConocoPhillips is a partner. ConocoPhillips is responsible for maintaining air permit compliance at Jupiter's sulfur recovery facility.

2. *Description of Project*: On August 21, 2008, the Department received a complete NSR-PSD permit application from ConocoPhillips. ConocoPhillips is proposing 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 NCVU project. The NCVU project will enable 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 will require 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, HPU, Raw Water Demineralizer System, Jupiter SRU/ATS Plant, and the FCCU. As a result of the NCVU Project, the Jupiter Plant feed rate capacity will need to be increased to approximately 235 LTD of sulfur

3. *Objectives of Project*: The primary objectives of the NCVU Project are to improve crude fractionation and energy efficiency of the refinery, and to increase crude processing capacity and crude feed flexibility to reduce feed costs.

4. *Alternatives Considered*: In addition to the proposed action, the Department also considered the "no-action" alternative. The "no-action" alternative would deny issuance of the air quality preconstruction permit to the proposed facility. However, the Department does not consider the "no-action" alternative to be appropriate because ConocoPhillips demonstrated compliance with all applicable rules and regulations as required for permit issuance. Therefore, the "no-action" alternative was eliminated from further consideration.

5. *A Listing of Mitigation, Stipulations, and Other Controls*: A list of enforceable conditions, including a BACT analysis, would be included in MAQP #2619-24.

6. *Regulatory Effects on Private Property*: The Department considered alternatives to the conditions imposed in this permit as part of the permit development. The Department determined that the

permit conditions are reasonably necessary to ensure compliance with applicable requirements and demonstrate compliance with those requirements and do not unduly restrict private property rights.

7. *The following table summarizes the potential physical and biological effects of the proposed project on the human environment.* The "no-action" alternative was discussed previously.

		Major	Moderate	Minor	None	Unknown	Comments Included
A	Terrestrial and Aquatic Life and Habitats			X			Yes
B	Water Quality, Quantity, and Distribution			X			Yes
C	Geology and Soil Quality, Stability and Moisture			X			Yes
D	Vegetation Cover, Quantity, and Quality			X			Yes
E	Aesthetics			X			Yes
F	Air Quality			X			Yes
G	Unique Endangered, Fragile, or Limited Environmental Resources			X			Yes
H	Demands on Environmental Resource of Water, Air and Energy			X			Yes
I	Historical and Archaeological Sites				X		Yes
J	Cumulative and Secondary Impacts			X			Yes

SUMMARY OF COMMENTS ON POTENTIAL PHYSICAL AND BIOLOGICAL EFFECTS: The following comments have been prepared by the Department.

A. Terrestrial and Aquatic Life and Habitats

As documented in the Montana Natural Heritage Program Data Report, the Yellowstone River Corridor has a rich diversity of aquatic, riverine, wetland, and adjacent upland habitats along its main-stem. The Yellowstone River, unlike most major rivers of the west, is free from major impoundments that have dramatically altered the hydrologic regime and is characterized as a relatively free-flowing river. The intact hydrology and river dynamics give rise to important cottonwood floodplain communities. Three species of cottonwoods: narwleafe cottonwood, black cottonwood, and plains cottonwood occur in gallery forests and terraces and provide habitat for nesting, wintering and migrating bald eagles and rookery sites for blue heron. Seasonal flooding is the principal process facilitating the establishment and regeneration of cottonwood forests and riparian communities. River and floodplain habitats are very important ecologically. Adjacent uplands include benches, slopes, cliffs, rock outcrops and historic river-bottom that support shrublands of sagebrush, grasslands consisting of bluebunch wheatgrass, and woodlands of primarily ponderosa pine. Channel gravel and sandbars provide habitat for spiny shoftshell and persistent-sepal yellowcress, although this species has not been relocated in recent years. Riparian communities include the plants beaked spikerush and Schweinitsz's flatsedge. Notable shorebirds recorded for this stretch include the Interior Least Tern. Two reptiles, the western hognose snake and the milk snake have been reported from the river corridor. The aquatic environment includes both cold water and warm water species, including Yellowstone cutthroat trout, pallid sturgeon, paddlefish, blue sucker, the sicklefin chub, and the sturgeon chub.

This permitting action would result in increased SO_2, NO_x, CO, VOC, PM, PM_{10}, and $PM_{2.5}$ emissions. While deposition of pollutants would occur, the Department determined that any impacts to terrestrial life and habitats from deposition of these pollutants would be minor. Habitat impacts could result in a change of diversity or abundance of terrestrial or aquatic life. However, the immediate area does not appear to contain any critical or unique wildlife habitat or aquatic life and the project would occur in an already disturbed area. Therefore, only minor impacts to terrestrial and aquatic life and habitats are anticipated.

B. Water Quality, Quantity and Distribution

ConocoPhillips is authorized to discharge treated wastewater effluent from its Billings refinery to the Yellowstone River via the Yegen Drain in accordance with Montana Pollutant Discharge Elimination System (MPDES) permit # MT-0000256. The receiving stream (the Yellowstone River) is classified as B-3 under Montana's Surface Water Quality Standards. Waters classified B-3 are to be maintained suitable for drinking, culinary, and food processing purposes, after conventional treatment; bathing, swimming, and recreation; growth and propagation of non-salmonid fishes and associated aquatic life, waterfowl and furbearers; and agricultural and industrial water supply. As part of the NCVU project, ConocoPhillips is proposing to construct a new parallel wastewater treatment facility to process desalter water from the new crude unit, with equipment consisting of an API oil/water separator, a primary dissolved air floatation unit, and the addition of a thermal oxidizer to control air emissions. The aeration system of the refinery's existing wastewater treatment facility would also be upgraded. This project would result in an increase in the existing average wastewater effluent flow rate. The flow rate would increase by approximately 65% from 350 gallons per minute (gpm) to 575 gpm. Pollutant loads would also increase as follows: Biochemical Oxygen Demand: 5.5 pounds per day (lbs/day); Chemical Oxygen Demand: 52 lbs/day; Total Suspended Solids: 6 lbs/day; Oil and Grease: 3 lbs/day, Ammonia: 3 lbs/day; and phenolic compounds: 0.009 lbs/day. MPDES permits are written to protect the beneficial uses specified in Montana's Surface Water Quality Standards. Therefore, because ConocoPhillips is expected to operate in compliance with its MPDES permit, only minor impacts to surface water are anticipated.

In addition, while deposition of pollutants would occur as a result of this project, the Department determined that any impact from the deposition of pollutants would be minor. Furthermore, this action would not result in a change in the quality or quantity of ground water. Therefore, only minor impacts to water quality, quantity, and/or distribution are anticipated.

C. Geology and Soil Quality, Stability and Moisture

The NCVU will be constructed on a closed Resource Conservation and Recovery Act (RCRA) permitted site known as the South Oily Sludge Pits (SOSP). Prior to 1988, the SOSP were used to store API separator sludge, a listed hazardous waste, in earthen pits. The sludge was removed and the pits were backfilled prior to closure. However, impacted earth materials and waste residuals remained in the soils associated with these pits. In order to prevent direct exposure to the surrounding soils and potential migration of contaminants into groundwater, the SOSP were covered with asphalt. The SOSP site is currently regulated under the authority of a RCRA post closure permit. Prior to constructing the NCVU at the SOSP area, the earth materials containing constituents of concern at concentrations above established levels must be removed. The refinery has modified its RCRA post-closure permit to facilitate the removal of impacted earth materials from the SOSP. The permit modification specifies that a RCRA staging pile can be constructed adjacent to the project area to allow stockpiling of soil prior to off-site shipping. The staging pile is a RCRA-regulated unit with specific performance criteria and permitted uses.

The permit modification also required submittal and Department approval of a detailed Corrective Measures Implementation (CMI) work plan to detail the impacted material removal and management. This CMI work plan was approved by the Department on June 19, 2008, with a subsequent addendum approved on July 17, 2008.

While deposition of pollutants would occur, the Department determined that any impacts from deposition of pollutants would be minor. This project would not change the soil stability or geologic substructure or result in any increased disruption, displacement, erosion, compaction, or moisture loss, which would reduce productivity or fertility at or near the site. No unique geologic or physical features would be disturbed. Therefore, minor impacts to geology and soil quality, stability, and moisture are anticipated.

D. Vegetation Cover, Quantity, and Quality

This project would be constructed on land already used for industrial activities. The vegetative cover, quantity, and quality would not be disturbed inside the facility boundaries. However, possible increases in actual emissions of SO_2, NO_x, CO, VOC, PM, PM_{10}, and $PM_{2.5}$ from historical emission levels may result in minor impacts to the diversity, productivity, or abundance of plant species in the surrounding areas. Issuance of this permit would cause minor, if any, changes in vegetation cover, quantity, or quality.

E. Aesthetics

This project would be constructed on land already used for industrial activities. Therefore, any additional impacts on aesthetics would be minimal.

F. Air Quality

The proposed project would result in increases in actual emissions of SO_2, NO_x, PM/PM_{10}, $PM_{2.5}$, CO, VOC, and HAPs from historical emission levels to the ambient air in the proposed project area. As detailed through air dispersion modeling in Section VI and Section VII of the permit analysis, any air quality impacts from these pollutants from the proposed project would be minor and would constitute negligible risk to human health and the environment.

Additionally, the estimated CO_2 emissions increase as a result of the NCVU project would be approximately 290 thousand tpy, which is approximately a 30% increase from the refinery's 2007 estimated CO_2 emissions. For comparison purposes, the estimated increase in CO_2 emissions resulting from the NCVU project is approximately 0.7% of the 2005 Montana state-wide estimated CO_2 emissions level of 40,565 thousand tons as documented in the *Montana Greenhouse Gas Inventory and Reference Case Projections 1990-2020*, September 2007. Therefore, any potential impacts from increased CO_2 emissions from the proposed project would be minor.

G. Unique Endangered, Fragile, or Limited Environmental Resources

In an effort to identify any unique endangered, fragile, or limited environmental resources in the area, the Department contacted the Montana Natural Heritage Program, Natural Resource Information System (NRIS). The NRIS search identified the following species of special concern located near the project area: Grasshopper Sparrow, Spiny Softshell, Loggerhead Shrike, Brewer's Sparrow, Spotted Bat, Greater Short-horned Lizard, Western Hog-nosed Snake, Peregrine Falcon, Common Sagebrush Lizard, and Milksnake. In this case, the project area was defined by the section, township, and range of the location with an additional 1-mile buffer zone. Because this project would occur at an existing industrial site and because

controlled emissions from this source would not cause or contribute to a violation of any ambient air quality standard, the Department determined that it would be unlikely that the proposed project would impact any species of special concern and that any potential impacts would be minor.

H. Demands on Environmental Resource of Water, Air and Energy

This project would not consume any significant additional energy or water resources. Further, as described in Section 7.F. of this EA, pollutant emissions generated would have minimal impacts on air quality in the immediate and surrounding area. The submitted modeling results show compliance with the NAAQS, MAAQS and applicable PSD increments. This project would result in a minor effect on the air resource, but resulting emissions will still comply with ambient air quality standards.

I. Historical and Archaeological Sites

This project would not disturb a greater land surface than is already occupied by the refinery. This project would occur within the boundaries of the refinery. The Department contacted the Montana Historical Society - State Historical Preservation Office (SHPO) in an effort to identify any historical and/or archaeological sites that may be present in the proposed area of construction and operation. SHPO conducted a cultural resource file search of the proposed area, and found no previously recorded sites within the designated search locales. It is SHPO's position, however, that any structure over fifty years of age is considered historic and is potentially eligible for listing on the National Register of Historic Places. If any structures are to be altered and are over fifty years old, SHPO recommends that they be recorded and a determination of their eligibility be made. No buildings over fifty years of age are proposed to be altered as a result of this project. Therefore, no impacts to any historical and archaeological sites would be anticipated.

J. Cumulative and Secondary Impacts

The NCVU project will provide the refinery the flexibility to process a larger percentage of heavy high-sulfur crude, and a crude slate with a greater naphtehnic acid content. The refinery anticipates, based on current production and future developments in Canada, that oil sands/SynBit crude oil will continue to be available and it will be necessary for the refinery to have the capability to process these crude oils as a larger percentage of the crude oil mix. As documented in the publication, "*Driving It Home: Choosing the Right Path for Fueling North America's Transportation Future*," a joint report prepared by the Natural Resources Defense Council, Western Resource Advocates, and Pembina Institute, the extraction of oil sands (also referred to as tar sands) has numerous environmental impacts. Oil sands consist of a mixture of 85% sand, clay, and silt; 5% water; and 10% crude bitumen – the "tar-like" substance that can be converted to oil. Because bitumen is so viscous, production of oil sands is typically accomplished through strip mining or steam injection into oil wells. These processes can use more water and require larger amounts of energy than conventional oil extraction. It is estimated that oil sands production can generate almost three times as much global warming pollution as conventional crude oil production because of the massive amounts of energy needed to extract, upgrade, and refine the oil. Strip mining of the oil sands often requires dredging of wetlands and the creation of tailings ponds, which can have high concentrations of pollutants that are toxic to aquatic life. Ultimately, the crude oil mixture run by the refinery is selected based on crude oil costs and the capability of the refinery to process the crude oil. The Department does not consider these impacts to be a result of the NCVU project. The NCVU project would not be creating a new market for these oil sands; rather, market forces are driving

the rate of oil sands extraction. Therefore, the cumulative and secondary impacts from the proposed project would be minor.

8. *The following table summarizes the potential economic and social effects of the proposed project on the human environment.* The "no-action" alternative was discussed previously.

		Major	Moderate	Minor	None	Unknown	Comments Included
A	Social Structures and Mores				X		Yes
B	Cultural Uniqueness and Diversity				X		Yes
C	Local and State Tax Base and Tax Revenue			X			Yes
D	Agricultural or Industrial Production			X			Yes
E	Human Health			X			Yes
F	Access to and Quality of Recreational and Wilderness Activities				X		Yes
G	Quantity and Distribution of Employment			X			Yes
H	Distribution of Population				X		Yes
I	Demands for Government Services			X			Yes
J	Industrial and Commercial Activity			X			Yes
K	Locally Adopted Environmental Plans and Goals				X		Yes
L	Cumulative and Secondary Impacts			X			Yes

SUMMARY OF COMMENTS ON POTENTIAL ECONOMIC AND SOCIAL EFFECTS: The following comments have been prepared by the Department.

A. Social Structures and Mores

The proposed facility would not cause a disruption to any native or traditional lifestyles or communities (social structures or mores) in the area because the project would occur at a previously disturbed industrial site. The proposed project would not change the nature of the site.

B. Cultural Uniqueness and Diversity

The proposed project would not cause a change in the cultural uniqueness and diversity of the area because the land is currently used as a petroleum refinery; therefore, the land use would not be changing. The use of the surrounding area would not change as a result of this project.

C. Local and State Tax Base and Tax Revenue

This project would have a minor effect on the local and state tax base and tax revenue because the proposed project is intended to increase crude distillation capacity. Therefore, tax revenue from the facility might increase slightly.

D. Agricultural or Industrial Production

The proposed project would not result in a reduction of available acreage or productivity of any agricultural land; therefore, agricultural production would not be affected. Industrial production would change slightly because the crude distillation capacity at this facility would increase.

E. Human Health

As described in Section 7.F of the EA, the impacts from this facility on human health would be minor. The project would include increases in NO_X, SO_2, PM/PM_{10}, $PM_{2.5}$, CO, and VOC emissions from recent emissions levels. However, the emissions would not result in a violation of the NAAQS, MAAQS, and applicable PSD increments. The air quality permit for this facility incorporates conditions to ensure that the facility would be operated in compliance with all applicable rules and standards. These rules and standards are designed to be protective of human health.

Additionally, as detailed in Section VII of the permit analysis, a health risk assessment was conducted to determine if the proposed wastewater treatment system thermal oxidizer would comply with the negligible risk requirement of MCA 75-2-215 and ARM 17.8.770. Since the concerned HAPs would not be expected to accumulate in the soil or surface water, only exposure occurring through inhalation was assessed. As defined in ARM 17.8.740(10), negligible risk is "*an increase in excess lifetime cancer risk of less than 1.0 x 10-6 for any individual pollutant, and 1.0 x 10-5 for the aggregate of all pollutants, and an increase in the sum of the non-cancer hazard quotients for all pollutants with similar toxic effects of less than 1.0 in order to determine negligible risk*." For the purposes of determining the negligible risk of the wastewater treatment thermal oxidizer, all HAPs associated with combustion of natural gas/RFG and the non-destructed portion of the vent gas to the thermal oxidizer were considered. All of the individual pollutant concentrations meet the acceptable cancer risk limit because they are less than 1.00E-06 for each pollutant and less than 1.00E-05 for the aggregate of all pollutants. Further, the sums of the chronic non-cancer hazard quotients are less than 1.0. Therefore, the proposed wastewater treatment system thermal oxidizer meets the criteria of ARM 17.8.770 and operation of the incinerator would be considered a negligible risk to public health, safety, welfare, and to the environment. Overall, any impacts to human health in the proposed project area would be minor.

F. Access to and Quality of Recreational and Wilderness Activities

The proposed action would not alter any existing access to or quality of any recreational or wilderness area activities. This project would not have an impact on recreational or wilderness activities because the site is far removed from recreational and wilderness areas or access routes. Furthermore, the facility is contained on private property and would continue to be contained within private property boundaries.

G. Quantity and Distribution of Employment

This project would result in minor impacts to the quantity and distribution of employment at the facility because temporary construction-related positions could result from this project, but any impacts to the quantity and distribution of employment would be minor.

H. Distribution of Population

The proposed project does not involve any significant physical or operational change that would affect the location, distribution, density, or growth rate of the human population.

I. Demands for Government Services

The demands on government services would experience a minor impact. The primary demand on government services would be the acquisition of the appropriate permits by the facility (including local building permits, as necessary, and a state air quality permit) and compliance verification with those permits.

J. Industrial and Commercial Activity

Overall, industrial production at the ConocoPhillips refinery would change slightly as a result of the project because the crude distillation capacity would increase by approximately 25%. Therefore, a minor impact on industrial activity at the ConocoPhillips refinery would be expected. Industrial and commercial activity in the neighboring area would not be anticipated to be affected, however.

K. Locally Adopted Environmental Plans and Goals

There are no locally adopted environmental plans and goals that are expected to be affected by the proposed change to emission limitations. ConocoPhillips must continue to comply with the State Implementation Plan and associated stipulations for the Billings/Laurel area.

L. Cumulative and Secondary Impacts

Increases in actual pollutant emissions of NO_X, SO_2, PM/PM_{10}, $PM_{2.5}$, CO, and VOC above recent historical levels may result in minor cumulative and secondary impacts to the human environment. However, the emissions would not result in a violation of the NAAQS, MAAQS, and applicable PSD increments. Therefore, the cumulative and secondary impacts from the proposed project would be minor.

Recommendation: No EIS is required.

If an EIS is not required, explain why the EA is an appropriate level of analysis: The current permitting action is for the construction and operation of a new crude and vacuum unit. MAQP #2619-24 includes conditions and limitations to ensure the facility would operate in compliance with all applicable rules and regulations. In addition, there are no significant impacts associated with this proposal.

Other groups or agencies contacted or which may have overlapping jurisdiction: Montana Historical Society – State Historic Preservation Office, Natural Resource Information System – Montana Natural Heritage Program, Department of Environmental Quality – Water Protection Bureau, Department of Environmental Quality – Waste and Underground Tank Management Bureau

Individuals or groups contributing to this EA: Department of Environmental Quality – Air Resources Management Bureau, Department of Environmental Quality – Water Protection Bureau, Department of Environmental Quality – Waste and Underground Tank Management Bureau, Montana Historical Society – State Historic Preservation Office, Natural Resource Information System – Montana Natural Heritage Program

EA prepared by: Moriah Peck, P.E.
Date: September 16, 2008