Montana Department of
ENVIRONMENTAL QUALITY
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February 14, 2012

Julian R. Stoll
Refinery Manager
ConocoPhillips Company
Billings Refinery
P.O. Box 30198
Billings, MT 59107

RE: Final Title V Operating Permit #OP2619-06

Dear Mr. Stoll:

The Department of Environmental Quality has prepared the enclosed Final Operating Permit #OP2619-06, for the Billings Refinery, located in Billings, Montana. Please review the cover page of the attached permit for information pertaining to the action taking place on Permit #OP2619-06.

If you have any questions, please contact Skye Hatten, the permit writer, at (406) 444-5287 or by email at shatten@mt.gov.

Sincerely,

Vickie Walsh
Air Permitting Program Supervisor
Air Resources Management Bureau
(406) 444-9741

Skye Hatten, P.E.
Environmental Engineer
Air Resources Management Bureau
(406) 444-5287

VW: sh:
Enclosure
Cc: Christopher Ajayi, US EPA Region VIII 8P-AR
Carson Coate, US EPA Region VIII, Montana Office
Randall Richert, P.E.,ConocoPhillips Company

STATE OF MONTANA
Department of Environmental Quality
Helena, Montana 59620

AIR QUALITY OPERATING PERMIT OP2619-06

Issued to: **ConocoPhillips Company**
Billings Refinery
401 South 23rd Street
P.O. Box 30198
Billings, MT 59107

Final Date: **February 14, 2012**
Expiration Date: **July 8, 2013**

Effective Date: **February 14, 2012**
Date of Decision: **January 12, 2012**
End of EPA 45-day Review: **January 9, 2012**
Proposed Issue Date: **November 23, 2011**
Draft Issue Date: **October 20, 2011**

Applications Deemed Technically Complete: **09/19/2011**
Applications Deemed Administratively Complete: **09/19/2011**
Significant Modification Applications Received: **08/28/2009, 12/06/2010, 09/19/2011**
AFS Number: 030-**111-0011A**

Permit Issuance and Appeal Processes: In accordance with Montana Code Annotated (MCA) Sections 75-2-217 and 218 and the Administrative Rules of Montana (ARM), ARM Title 17, Chapter 8, Subchapter 12, Operating Permit Program, this operating permit is hereby issued by the Department of Environmental Quality (Department) as effective and final on February 14, 2012. This permit must be kept on-site at the above named facility.

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Terms not otherwise defined in this permit or in the Definitions and Abbreviations Appendix of this permit have the meaning assigned to them in the referenced regulations.

SECTION I. GENERAL INFORMATION

The following general information is provided pursuant to ARM 17.8.1210(1).

Company Name: ConocoPhillips Company, Billings Refinery

Mailing Address: P.O. Box 30198, 401 South 23rd Street

City: Billings **State:** Montana **Zip:** 59107-0198

Plant Location: NW¼ Section 2, Township 1 South, Range 26 East, Yellowstone County

Responsible Official: Steven Steach **Phone:** (406) 255-2551

Alternate Responsible Official: Paul E. Seyler **Phone:** (406) 255-7593

Facility Contact Person: Randall Richert **Phone:** (406) 255-2580

Primary SIC Code: 2911

Nature of Business: Petroleum Refining

Description of Process: The refining process distills crude oil using heat. This distillation separates the crude oil into its component parts. The refiner then cracks some of the heavier molecules by applying heat in the presence of a catalyst to make the reaction take place. These raw products are then treated in several ways to take out impurities. Finally, the proper liquids and additives are blended to create the desired product.

The ConocoPhillips Billings Refinery also includes the Jupiter Sulfur Recovery Facility. The recovery facility utilizes sulfur from the refining process to produce fertilizer.

The ConocoPhillips Pipeline Company's Billings Transportation Operations (ConocoPhillips Pipeline Company) is a support facility for the ConocoPhillips Billings Refinery. As such, it is included in conjunction with the refinery for Prevention of Significant Deterioration (PSD), Maximum Achievable Control Technology (MACT), and other permitting determinations.

The transportation operations were previously permitted as part of the refinery's Title V Operating Permit #OP2619-01, and is still contained as part of the most recent Montana Air Quality Permit (MAQP) #2619-27. However, since there are separate management structures, the facility requested to separate the transportation operations from the refinery in a separate operating permit, which has been assigned Operating Permit #OP4056-00.

SECTION II. SUMMARY OF EMISSIONS UNITS

The emission units regulated by this permit are the following (ARM 17.8.1211):

Emission Unit ID	Description	Pollution Control Device/Practice
EU001	**Boilers**: - Main Boiler House Stack: Boilers B-1, B-2, B-5, and B-6, and - Temporary Boiler.	None
EU002	**FCCU** FCCU Regenerator	None/ GOHDS Outage Plan
EU003	**Fuel Gas Combustion Units** 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-23, H-24, H-3901, H-8401, H-8402, H-9401, 9501, 9502, and 9701.	None/ 40 CFR 60, Subpart J
EU004	**PMA Process Unit** - PMA Process Heater (H-3201)	None
EU005	**Refinery Flare ("Refinery Main Plant Relief Flare")** - Emergency Flare & Spare	Flare is control equipment
EU006	**Refinery Fugitive Emissions** - Cryogenic Unit, - C-23 Compressor Station, - Hydrogen Membrane Unit, - Gasoline Merox Unit, - Hydrogen Plant Feed System, - Alkylation Unit Butane Defluorinator Project, - PMA Process Unit, - Depropanizer Project, - Crude Topping Units, - Crude Vacuum Unit, - Fluidized Catalytic Cracking Unit, - Catalytic Reforming Units #1 & #2, - Alkylation Unit, - Hydrodesulfurization Units #1 & #2, - Gas Oil Hydrotreating Unit, - Delayed Coking Unit, - Upgrading, Treating, and Recovery Units, - Cryo Debutanizer Unit, - Butamer/Feed Prep Unit, - Gas Recovery Plant Unit, - Naphtha Splitter Unit, - Sat Gas Plant Unit, - Hydrogen Purification Unit, - Railroad loading rack, - Cooling Towers, and - Tank Farm.	None
EU007	**Sulfur Recovery Facility** - Ammonium Thiosulfate (ATS) Unit, - Ammonium Sulfide Unit, - Sulfur Recovery Unit (SRU), and - Jupiter SRU Flare.	Flare and Incinerators/ CAM Plan

Emission Unit ID	Description	Pollution Control Device/Practice
EU008	**Storage Tanks (non-wastewater)** (*see Transportation Operations #OP4056-00 for additional tankage)* Refinery MACT 1 Group 1: - Crude Oil Storage Tanks #1 and #2; - Gasoline, Naphtha, and Other Storage Tanks: #3, #5, #7, #9, #12, #16, #21, #41, #42, #45, #46, #49, #52, #55, #72, #75, #80, #86, #87, #102, #110, #851, #2909 Refinery MACT 1 Group 2: - Asphalt and PMA Storage Tanks #4, #62, #100, #101 & #3201 - Jet A, Distillate, and Diesel Storage Tanks #8, #10, #14, #20, #33, #47, #48, #53, #54, #57, #74, - Residual and Fuel Oil Storage Tanks #6, #17,# 39, #40, #69, #70, #81, #104, #107 - Other Storage Tanks #11, #13, #18, #32, #59, #60, #82, #88, #91, #92, #116, #801 Organic Liquid Distribution MACT: - Proto Gas Tanks #2901 - #2907 - Dye & Other Tanks #78, #79 & #109 Other - Propane Tanks	None, Primary and possibly secondary seals on floating roofs
EU010	**Wastewater Treatment** Wastewater Tanks: - #15 – sour water - #34, #35 & #164 – Slop Oil - #4523 - WW Surge Wastewater Separators: - #163 – primary separator - #169 & #170 – secondary separators (CPI) - #4510 & #4511 – Desalter Break - #4512 & #4513 – Coker Break Oily Water Sewer Drain Systems: - Coker unit, - gas oil hydrotreater, - No.1 Hydrogen Unit (20.0 MMscfd), - No.2 Hydrogen Unit, - No.5 HDS Unit, - C-23 compressor station, - Alkylation Unit Butane Defluorinator Project, - Alkylation Unit Depropanizer Project, - #3 Sour Water Stripper, - South Tank Farm, and - Associated wastewater tanks.	None Carbon Canisters
EU011	**Miscellaneous Process Vents**	None
EU012	**Catalytic Reforming Units 1 & 2**	None

SECTION III. PERMIT CONDITIONS

The following requirements and conditions are applicable to the facility or to specific emission units located at the facility (ARM 17.8.1211, 1212, and 1213).

A. Facility-Wide

Conditions	Rule Citation	Rule Description	Pollutant/Parameter	Limit
A.1	ARM 17.8.105	Testing Requirements	Testing Requirements	-------
A.2	ARM 17.8.106	Source Testing Protocol	Testing, Recordkeeping, and Reporting Requirements	-------
A.3	ARM 17.8.304(1)	Visible Air Contaminants	Opacity	40%
A.4	ARM 17.8.304(2)	Visible Air Contaminants	Opacity	20%
A.5	ARM 17.8.304(3)	Visible Air Contaminants	Opacity	60%
A.6	ARM 17.8.308(1)	Particulate Matter, Airborne	Fugitive Opacity	20%
A.7	ARM 17.8.308(2)	Particulate Matter, Airborne	Reasonable Precautions	-------
A.8	ARM 17.8.308	Particulate Matter, Airborne	Reasonable Precaution, Construction	20%
A.9	ARM 17.8.309	Particulate Matter, Fuel Burning Equipment	Particulate Matter	$E= 0.882 * H^{-0.1664}$ or $E= 1.026 * H^{-0.233}$
A.10	ARM 17.8.310	Particulate Matter, Industrial Processes	Particulate Matter	$E= 4.10 * P^{0.67}$ or $E= 55 * P^{0.11} - 40$
A.11	ARM 17.8.322(4) and 1979 State Implementation Plan (SIP)	Sulfur Oxide Emissions, Sulfur in Fuel	Sulfur in Fuel (liquid or solid fuels)	1 lb/MMBtu fired
A.12	ARM 17.8.322(5)	Sulfur Oxide Emissions, Sulfur in Fuel	Sulfur in Fuel (gaseous)	50 gr/100 CF
A.13	ARM 17.8.324(3)	Hydrocarbon Emissions, Petroleum Products	Gasoline Storage Tanks	-------
A.14	ARM 17.8.324	Hydrocarbon Emissions, Petroleum Products	65,000-Gallon Capacity	-------
A.15	ARM 17.8.324(2)	Hydrocarbon Emissions, Petroleum Products	Oil-effluent Water Separator	-------
A.16	ARM 17.8.325	Motor Vehicles	Air Pollution Control Devices	-------
A.17	ARM 17.8.615	Firefighting Training Permit	Firefighting Requirements	-------
A.18, A.19	ARM 17.74.336; 40 CFR 61, Subpart M	Asbestos	Asbestos	-------
A.20	ARM 17.8.341	National Emission Standards for Hazardous Air Pollutants (NESHAPs)	All Applicable Provisions of 40 CFR 61, Subpart FF	-------
A.21	ARM 17.8.342	NESHAPs - 40 CFR 63 General Provisions	Start-up, Shutdown, Malfunction (SSM) Plans	Submittal
A.22	40 CFR 68	Chemical Accident Prevention	Risk Management Plan	-------
A.23	ARM 17.8.749	Operating Requirements	All systems totally enclosed	-------
A.24	ARM 17.8.749	Permit Conditions	SO_2	3103 ton/yr
A.25	ARM 17.8.1212	Recordkeeping Requirements	SO_2	-------
A.26	40 CFR 51	SIP	SO_2	-------
A.27	40 CFR 51	SIP – State Only	SO_2	-------
A.28	40 CFR 51	SIP	Sulfur Bearing Gases	-------

A.29	40 CFR 51	SIP	Quantify Emissions	-------
A.30	ARM 17.8.1212	Maintain Records	5 Years	-------
A.31	ARM 17.8.1212	Notification and Reporting	Various	As specified
A.32	ARM 17.8.749 & 17.8.801(7)	Refinery and Terminal	One Source for New Source Review and MACT Purposes	-------
A.33	ARM 17.8.1211(1)(c) and 40 CFR Part 98	Greenhouse Gas Reporting	Reporting	-------
A.34	ARM 17.8.1212	Reporting Requirements	Compliance Monitoring	-------
A.35	ARM 17.8.1207	Reporting Requirements	Annual Certification	-------

Conditions

A.1. Pursuant to ARM 17.8.105, 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 test, emission or ambient, for such periods of time as may be necessary using methods approved by the Department.

Compliance demonstration frequencies that list "as required by the Department" refer to ARM 17.8.105. In addition, for such sources, compliance with limits and conditions listing "as required by the Department" as the frequency, is verified annually using emission factors and engineering calculations by the Department's compliance inspectors during the annual emission inventory review; in the case of Method 9 tests, compliance is monitored during the regular inspection by the compliance inspector.

A.2. Pursuant to ARM 17.8.106, all emission source testing, sampling and data collection, recording analysis, and transmittal must be performed, maintained, and reported in accordance with the Montana Source Test Protocol and Procedures Manual (dated July 1994 unless superseded by rulemaking), unless alternate methods are approved by the Department.

A.3. Pursuant to ARM 17.8.304(1), ConocoPhillips shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed on or before November 23, 1968, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes, unless otherwise specified by rule or in this permit. This rule does not apply to emissions from new stationary sources listed in ARM 17.8.340 for which a visible emission standard has been promulgated.

A.4. Pursuant to ARM 17.8.304(2), ConocoPhillips shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23,1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes, unless otherwise specified by rule or in this permit. This rule does not apply to emissions from new stationary sources listed in ARM 17.8.340 for which a visible emission standard has been promulgated.

A.5. Pursuant to ARM 17.8.304(3), during the building of new fires, cleaning of grates, or soot blowing, the provisions of ARM 17.8.304(1) and (2) shall apply, except that a maximum average opacity of 60% is permissible for not more than one 4-minute period in any 60 consecutive minutes. Such a 4-minute period means any 4 consecutive minutes.

A.6. Pursuant to ARM 17.8.308(1), ConocoPhillips shall not cause or authorize the production, handling, transportation, or storage of any material unless reasonable precautions to control emissions of particulate matter are taken. Such emissions of airborne particulate matter from any stationary source shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes, unless otherwise specified by rule or in this permit.

A.7. Pursuant to ARM 17.8.308(2), 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, unless otherwise specified by rule or in this permit.

A.8. Pursuant to ARM 17.8.308(3), ConocoPhillips shall not operate a construction site or demolition project unless reasonable precautions are taken to control emissions of airborne particulate matter. Such emissions of airborne particulate matter from any stationary source shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes, unless otherwise specified by rule or in this permit.

A.9. Pursuant to ARM 17.8.309, unless otherwise specified by rule or in this permit, ConocoPhillips shall not cause or authorize particulate matter caused by the combustion of fuel to be discharged from any stack or chimney into the outdoor atmosphere in excess of the maximum allowable emissions of particulate matter for existing fuel burning equipment and new fuel burning equipment, calculated using the following equations:

For existing fuel burning equipment (installed before November 23, 1968):
E = 0.882 * H-0.1664

For new fuel burning equipment (installed on or after November 23, 1968):
E = 1.026 * H-0.233

Where H is the heat input capacity in million British thermal units (MMBtu) per hour and E is the maximum allowable particulate emissions rate in pounds per MMBtu. When two or more fuel-burning units are connected to a single stack, the combined heat input of all units connected to the stack shall not exceed that allowable for the same unit connected to a single stack. This rule does not apply to emissions from new stationary sources listed in ARM 17.8.340 for which a visible emission standard has been promulgated.

A.10. Pursuant to ARM 17.8.310, unless otherwise specified by rule or in this permit, ConocoPhillips shall not cause or authorize particulate matter to be discharged from any operation, process, or activity into the outdoor atmosphere in excess of the maximum hourly allowable emissions of particulate matter, calculated using the following equations:

For process weight rates up to 30 tons per hour: E = 4.10 * P0.67

For process weight rates in excess of 30 tons per hour: E = 55.0 * P0.11 – 40

Where E is the rate of emissions in pounds per hour and p is the process weight rate in tons per hour.

A.11. Pursuant to ARM 17.8.322(4), ConocoPhillips shall not burn liquid or solid fuels containing sulfur in excess of 1 pound per million BTU fired, unless otherwise specified by rule or in this permit. This rule shall be interpreted to mean that no person shall burn solid, liquid, or gaseous fuels such that the aggregate sulfur content of all fuels burned within a plant during any day exceeds 1 pound of sulfur per million BTU fired. The rule shall be interpreted to allow for a daily deviation of 0.1 pound of sulfur per million BTU fired. The rule shall be interpreted to allow the blending of all fuels burned in a plant during a given time period in determining the aggregate sulfur content for purposes of the rule, and it shall not be construed to require blending or physical mixing of fuels at any given furnace or heater within the plant complex (EPA-approved State Implementation Plan (SIP), September 1979).

A.12. Pursuant to ARM 17.8.322(5), ConocoPhillips shall not 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, unless otherwise specified by rule or in this permit. This rule shall be interpreted to mean that no person shall burn solid, liquid, or gaseous fuels such that the aggregate sulfur content of all fuels burned within a plant during any day exceeds one pound of sulfur per million BTU fired. The rule shall be interpreted to allow for a daily deviation of 0.1 pound of sulfur per million BTU fired. The rule shall be interpreted to allow the blending of all fuels burned in a plant during a given time period in determining the aggregate sulfur content for purposes of the rule, and it shall not be construed to require blending or physical mixing of fuels at any given furnace or heater within the plant complex (EPA-approved SIP, September 1979).

A.13. Pursuant to ARM 17.8.324(3), ConocoPhillips shall not 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 or is a pressure tank as described in ARM 17.8.324(1), unless otherwise specified by rule or in this permit.

A.14. Pursuant to ARM 17.8.324, unless otherwise specified by rule or in this permit, ConocoPhillips shall not place, store or hold in any stationary tank, reservoir or other container of more than 65,000-gallon capacity any crude oil, gasoline or petroleum distillate having a vapor pressure of 2.5 pounds per square inch absolute or greater under actual storage conditions, unless such tank, reservoir or other container is a pressure tank maintaining working pressure sufficient at all times to prevent hydrocarbon vapor or gas loss to the atmosphere, or is designed and equipped with a vapor loss control device, properly installed, in good working order and in operation.

A.15. Pursuant to ARM 17.8.324(2), unless otherwise specified by rule or in this permit, ConocoPhillips shall not use any compartment of any single or multiple-compartment oil-effluent water separator which compartment receives effluent water containing 200 gallons a day or more of any petroleum product from any equipment processing, refining, treating, storing or handling kerosene or other petroleum product of equal or greater volatility than kerosene, unless such compartment is equipped with a vapor loss control device, constructed so as to prevent emission of hydrocarbon vapors to the atmosphere, properly installed, in good working order and in operation.

A.16. ConocoPhillips shall comply with ARM 17.8.325. ConocoPhillips may monitor and certify compliance with ARM 17.8.325 by initially surveying its ConocoPhillips-owned on-road vehicles for the proper pollution control equipment. The survey shall be kept updated with the addition of any newly obtained ConocoPhillips-owned on-road vehicles. ConocoPhillips shall also revise its on-road vehicle maintenance procedure to state that on-road vehicle pollution control equipment removed for maintenance must be repaired and reinstalled or replaced.

A.17. ConocoPhillips shall maintain records that they have applied for and, if issued, complied with any required Firefighter Training permit to conduct open burning for fire training purposes (ARM 17.8.615).

A.18. Pursuant to ARM 17.74.336, ConocoPhillips shall comply with all the limitations and requirements of their Asbestos Abatement Annual Permit #MTF06-0010, or its updates.

A.19. ConocoPhillips shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements contained in the National Emission Standards for Hazardous Air Pollutants (NESHAPs) provisions, as appropriate, of 40 CFR 61, Subpart M Asbestos.

A.20. ConocoPhillips shall manage and treat the facility waste, including each process wastewater stream that meets the definition in 40 CFR 61.341, in accordance with the applicable requirements of 40 CFR 61.342(e) (Subpart FF "BQ6" Alternative). ConocoPhillips shall comply with applicable testing, monitoring and inspection, recordkeeping and reporting requirements set out under 40 CFR 61, Subpart FF (ARM 17.8.341).

A.21. Pursuant to ARM 17.8.342 and 40 CFR 63.6, ConocoPhillips shall submit to the Department a copy of any startup, shutdown, and malfunction (SSM) plan required under 40 CFR 63.6(e)(3) within 30 days of the effective date of this operating permit (if not previously submitted), within 30 days of the compliance date of any new National Emission Standard for Hazardous Air Pollutants (NESHAPs) or Maximum Achievable Control Technology (MACT) standard, and within 30 days of the revision of any such SSM plan, when applicable. The Department requests submittal of such plans in electronic form, when possible.

A.22. A Risk Management Plan, developed in accordance with 40 CFR 68, shall be registered with the United States Environmental Protection Agency by June 21, 1999. ConocoPhillips shall submit a certification statement to the Department that states ConocoPhillips is in compliance with the requirements of 40 CFR 68, including registration and updates of their Risk Management Plan pursuant to §112(r) of the FCAA (40 CFR 68.150, 160, and 190).

A.23. 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 and ARM 17.8.1211).

A.24. Unless otherwise specified by rule or in this permit, ConocoPhillips shall not cause or authorize total sulfur dioxide (SO2) emissions from refinery and sulfur recovery facilities to exceed the limit of 3103 ton/yr. In addition, where applicable, all other federal emission limitations shall be met (ARM 17.8.749 and ARM 17.8.1211).

A.25. ConocoPhillips shall maintain, under ConocoPhillips's control, a log of total SO2 emissions from the refinery and sulfur recovery facilities. This log shall be used to monitor compliance with the limitation as specified in Section III.A.24 (ARM 17.8.1212).

A.26. Pursuant to the June 12, 1998, Board Order adopting a SO2 control plan (Appendix E of this permit), ConocoPhillips shall comply with all requirements of Exhibit A and Attachment 1 of the plan. In addition, ConocoPhillips shall comply with all terms as set forth by this permit (Board Order signed on June 12, 1998, the control plan was partially approved/partially disapproved by EPA on May 2, 2002; parts of the requirement that were disapproved remain "State Only" along with those provisions intended to be "State Only" that were not submitted to EPA).

A.27. Pursuant to the June 12, 1998, Board Order adopting a SO2 control plan (Appendix E of this permit), ConocoPhillips shall comply with all requirements of Exhibit A-1 and corresponding attachments (Board Order signed on June 12, 1998, this requirement is "State Only").

A.28. ConocoPhillips shall utilize appropriate maintenance, repair, and operating practices to control emissions of sulfur bearing gases from minor sources such as ducts, stacks, valves, vents, vessels, and flanges that are not otherwise subject to the Stipulation and Exhibit A (Billings/Laurel SO2 Control Plan, approved into the SIP by EPA on May 2, 2002).

A.29. ConocoPhillips shall use good engineering judgment and appropriate engineering calculations to quantify emissions from activities that are not otherwise addressed by the Stipulation and Exhibit A, but are known to contribute to emissions from sources listed in Exhibit A, Section 1(B). In

addition, ConocoPhillips shall account for such emissions in determining compliance with all applicable emission limits contained in Exhibit A, Section 3 (Billings/Laurel SO2 Control Plan, approved into the SIP by EPA on May 2, 2002).

A.30. ConocoPhillips shall maintain, under ConocoPhillip's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by the Department and EPA, and must be submitted to the Department upon request (ARM 17.8.1212).

A.31. 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 (ARM 17.8.749 and 17.8.1212):

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 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.

A.32. ConocoPhillips Company, Billings Refinery (including the Jupiter Sulphur plant) and the ConocoPhillips Pipe Line Company - Billings Transportation Operations facility shall be considered one source for the purpose of permitting these facilities with respect to New Source Review. Based on the following determinations, the facilities are considered one source (ARM 17.8.749 and 17.8.801(7)):

a. The refinery and the terminal are under common ownership and control;

b. The refinery and the terminal are contiguous and adjacent; and

c. The terminal is considered a support facility to the refinery.

A.33. Pursuant to ARM 17.8.1211(1)(c) and 40 CFR Part 98, ConocoPhillips shall comply with requirements of 40 CFR Part 98 – Mandatory Greenhouse Gas Reporting, as applicable (ARM 17.8.1211(1)(c), NOT an applicable requirement under Title V).

A.34. On or before February 15th and August 15th of each year, ConocoPhillips shall submit to the Department the compliance monitoring reports required by Section V.D. These reports must contain all information required by Section V.D, as well as the information required by each individual emissions unit. For the reports due by February 15th of each year, ConocoPhillips may submit a single report provided that it contains all the information required by Section V.B & V.D (ARM 17.8.1212).

any application form, report, or compliance certification submitted pursuant to ARM Title 17, Chapter 8, Subchapter 12 (including semiannual monitoring reports), shall contain certification by a responsible official of truth, accuracy and completeness. This certification and any other certification required under ARM Title 17, Chapter 8, Subchapter 12, shall state that, ***"based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete."***

A.35. By February 15th of each year, ConocoPhillips shall submit to the Department the compliance certification report required by Section V.B. The annual certification report required by Section V.B must include a statement of compliance based on the information available which identifies any observed, documented or otherwise known instance of noncompliance for each applicable requirement (ARM 17.8.1207).

any application form, report, or compliance certification submitted pursuant to ARM Title 17, Chapter 8, Subchapter 12 (including annual certifications), shall contain certification by a responsible official of truth, accuracy and completeness. This certification and any other certification required under ARM Title 17, Chapter 8, Subchapter 12, shall state that, ***"based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete."***

B. EU001 – Boilers

Main Boiler House Stack: Boilers B-1, B-2, B-5, and B-6; and Temporary Boiler

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirement
B.1, B.14, B.17, B.18, B.28, B.29, B.30, B.34 - B.38	SO_2	300 ton/yr from fuel oil combustion plant-wide, on a rolling 365-day average	CEMS	Ongoing	Quarterly
			Method 6/6C	Annually	Semianually
B.2, B.14, B.17, B.18, B.28, B.29, B.30, B.34 - B.38	SO_2	1407.8 ton/yr, 3.857 ton/day, 321.4 lb/hr on a rolling 24-hour average basis	CEMS	Ongoing	Quarterly
			Method 6/6C	Annually	Semiannually
B.3, B.14, B.17, B.18, B.28, B.29, B.30, B.34 - B.38	SIP: SO_2	964.2 lb/3-hr 7,713.6 lb/cal. day 2,815,464 lb/cal. yr	CEMS	Ongoing	Quarterly
			Method 6/6C	Annually	Semiannually
B.4, B.15, B.16, B.32, B.37 & B.38	Refinery Fuel Gas	40 CFR 60, Subpart J	40 CFR 60, Subpart J	40 CFR 60, Subpart J	
B.4, B.15, B.16, B.17, B.28, B.30, B.32, B.34 – B.38	H_2S	0.10 grains/dscf on a three-hour basis	CEMS	Ongoing	Quarterly
			RATA (Method 11)	Annually	Semiannually
B.5, B.19, B.28, B.34, B.35, B.37 & B.38	Opacity	40% / 20%	Method 9	As required by the Department and Section III.A.1	
B.6, B.20, B.28, B.29, B.34, B.35, B.37 & B.38	Particulate Matter Fuel Burning Equipment	$E= 0.882 * H^{-0.1664}$ Or $E= 1.026 * H^{-0.233}$	Method 5		
B.7, B.21, B.31, B.40 & B.38	B-5 and B-6	40 CFR 60, Subpart Db	40 CFR 60, Subpart Db	40 CFR 60, Subpart Db	
B.8, B.22, B.33, B.37 & B.38	B-5 and B-6: NOx	Must be equipped with Ultralow NOx burners	Certification	On-going	
B.9, B.23, B.24, B.25, B.28, B.29, B.30, B.34, B.35, B.37 & B.38	B-5 and B-6: NOx	When fired on RFG, 0.03 lb/MMBtu on a 365-day average or 24.05 ton/yr on a 365-day average	CEMS	Ongoing	
			Method 7 and 19	Every 5 years	
B.10, B.23, B.24, B.25, B.28, B.29, B.30, B.34, B.35, B.37 & B.38	B-5 and B-6: CO	When fired on RFG, 0.04 lb/MMBtu on a rolling 365-day average	CEMS	Ongoing	
			Method 10	Every 5 years	
B.11, B.26, B.29, B.33, B.37 & B.438	B-5 and B-6: VOC	4.32 tons/rolling 12-calendar month	Emission Calculations	Semiannually	
B.12, B.21, B.31, B.37 & B.38	Temporary Boiler	40 CFR 60, Subpart Dc	40 CFR 60, Subpart Dc	Semiannually	
B.13, B.27, B.33, B.37 & B.38	Temporary Boiler	No more than 51 MMBtu/hr natural gas-fired boiler, operated up to 8 weeks per 12-month period.	Certification	Semiannually	

Conditions

B.1. ConocoPhillips shall not exceed 300 tons per year (ton/yr) SO_2 emissions from fuel oil combustion plant-wide, based on a rolling 365-day average. During documented periods of natural gas curtailment, SO_2 emissions from the burning of any liquid fuel shall not be included in the 365-day average (Consent Decree, ARM 17.8.749).

B.2. SO_2 emissions from the Main Boiler House Stack are limited to 321.4 pounds per hour (lb/hr) calculated on a rolling 24-hour average, 3.857 ton/day, and 1407.8 ton/yr (fuel oil and fuel gas combustion) (ARM 17.8.749, ARM 17.8.1211, ARM 17.8.340, and 40 CFR 60.105).

B.3. SO_2 emissions from the Main Boiler House Stack are limited to 964.2 pounds per 3-hour period, 7,713.6 pounds per calendar day, and 2,815,464 pounds per calendar year (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

B.4. ConocoPhillips shall comply with all applicable requirements of 40 CFR 60, Subpart J-Standards of Performance for Petroleum Refineries, as it applies to fuel gas combustion devices. Each boiler used to combust Refinery Fuel Gas (RFG) at ConocoPhillips are fuel gas combustion devices and are considered "affected facilities" under 40 CFR 60, Subparts A and J. Fuel-fired equipment exclusively burning natural gas are not "fuel gas combustion devices" and are not "affected facilities" under 40 CFR 60, Subparts A and J during such periods.

Except for periods of startup, shutdown, and malfunction, ConocoPhillips shall not burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 milligrams per dry standard cubic meter (mg/dscm) (0.10 grains per dry standard cubic foot (gr/dscf), or ~160 parts per million volume dry basis (ppmvd)) per rolling 3-hour period (Consent Decree, ARM 17.8.749, ARM 17.8.340 and 40 CFR 60, Subpart J).

B.5. ConocoPhillips shall not cause or authorize emissions to be discharged into the outdoor atmosphere from the Main Boiler House Stack, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes, except during times that the exhaust from only boilers B-5 and B-6 are being routed to the main boiler house stack, the opacity limit is 20% (ARM 17.8.304).

B.6. ConocoPhillips shall not cause or authorize particulate matter caused by the combustion of fuel to be discharged from any stack or chimney into the outdoor atmosphere in excess of the maximum allowable emissions of particulate matter for existing fuel burning equipment and new fuel burning equipment, calculated using the following equations:

For existing fuel burning equipment (installed before November 23, 1968):
$E = 0.882 * H^{-0.1664}$

For new fuel burning equipment (installed on or after November 23, 1968):
$E = 1.026 * H^{-0.233}$

Where H is the heat input capacity in MMBtu per hour and E is the maximum allowable particulate emissions rate in pounds per MMBtu (ARM 17.8.309).

B.7. ConocoPhillips shall comply with all applicable requirements of 40 CFR 60, Subpart Db-Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. Boilers B-5 and B-6 are subject to the Subpart Db requirements (ARM 17.8.340; and 40 CFR 60, Subpart Db).

B.8. ConocoPhillips shall equip boilers B-5 and B-6 with Ultralow NO_x Burners (ULNB) (ARM 17.8.752).

B.9. NO_x emissions from boilers B-5 and B-6 shall each, when fired on RFG, not exceed 0.03 pounds per million British thermal unit (lb/MMBtu) based on a rolling 365-day average, or 24.05 ton/yr based on a rolling 365-day average (ARM 17.8.752).

B.10. Carbon Monoxide (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).

B.11. Volatile organic compound (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).

B.12. Any temporary boiler constructed, modified, or reconstructed after June 9, 1989 shall comply with the provisions of 40 CFR 60, Subpart Dc (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60, Subpart Dc).

B.13. ConocoPhillips shall operate a temporary natural gas-fired boiler for up to 8 weeks per rolling 12-month period. 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).

Compliance Demonstration

B.14. ConocoPhillips shall install and operate a SO_2 continuous emission monitor system (CEMS) and a volumetric flow rate monitor on the Main Boiler House Stack. SO_2 and volumetric flow rate monitors shall comply with all applicable provisions of 40 CFR Part 60, Appendix B, Performance Specifications 2, 3, and 6 as appropriate and the quality assurance/quality control requirements of 40 CFR 60 Appendix F ((ARM 17.8.749 and ARM 17.8.1211) and Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

B.15. ConocoPhillips shall conduct all monitoring and testing as required by 40 CFR 60, Subpart J, Standards of Performance for Petroleum Refineries, to monitor compliance with Section III.B.4. ConocoPhillips shall install, calibrate, maintain, and operate a H_2S CEMS to continuously monitor and record the concentration (dry basis) of H_2S in the RFG before being burned in any fuel gas combustion device, or develop an Alternate Monitoring Plan (AMP), as required by 40 CFR 60, Subparts A and J. Compliance with the fuel gas H_2S concentration limit set out in Section III.B.4 shall be monitored based on 3-hour rolling average H_2S concentrations, determined by utilizing data taken from the CEMS and other Department-approved sampling methods.

The H_2S CEMS shall be installed, certified, and operated in accordance with Performance Specification 7 (40 CFR 60, Appendix B) to meet applicable provisions of 40 CFR 60.105(a)(4), 60.7, and 60.13. The H_2S CEMS shall meet the quality assurance and quality control requirements set out in 40 CFR 60, Appendix F (annual Relative Accuracy Test Audits (RATAs)), as provided by the SO_2 Stipulation. The CEMS shall meet applicable quarterly data recovery rates and other provisions of §6(A) of the SO_2 Stipulation (ARM 17.8.340 and 40 CFR 60, Subpart J, Consent Decree, Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, ARM 17.8.1212, and ARM 17.8.1213).

B.16. ConocoPhillips shall operate and maintain a continuous flow rate monitor on the RFG header. Accuracy determinations for the RFG flow rate monitor shall be required at least once every 48 months or more frequently as routine refinery turn-arounds allow (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

B.17. Compliance with the emission limitations, where applicable, shall be monitored by using data from the CEMS and other Department-approved sampling methods (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

a. The above does not relieve ConocoPhillips from meeting any applicable requirements of 40 CFR Part 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, particulate matter (PM), particulate matter less than 10 microns (PM_{10}), and VOCs.

c. Reporting requirements shall be consistent with 40 CFR Part 60, or as specified by the Department. CEMS data and calculations shall be submitted to the Department on a quarterly basis.

d. All gaseous (SO_2 and H_2S) CEMS shall be required to comply with quality assurance/quality control procedures in 40 CFR Part 60, Appendix F. Said CEMS shall be required to be maintained such that it is available and operating at least 90% of the source operating time during any reporting period (quarterly).

e. CEM systems 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 CEM system 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 monitored. The Department shall approve such contingency plans.

B.18. In order to accurately monitor the SO_2 emission rates in pounds per hour for the Main Boiler House Stack, ConocoPhillips shall perform annual source testing using EPA-approved methods (40 CFR Part 60, Appendix A, Methods 1-4 and 6/6C as appropriate for the Stipulation (STIP) and Exhibit A) or an equivalent method approved by the Department and EPA, and in accordance Section III.A.2 of this permit (ARM 17.8.106).

The annual RATAs required by Section 6(C) and (D) of the STIP may be substituted for the annual source tests, provided that the flow rate RATA and the concentration RATA are performed simultaneously and additional calculations are made to determine and report the data in pounds per hour of SO_2 ((ARM 17.8.749 and ARM 17.8.1211) and Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

B.19. As required by the Department and Section III.A.1, ConocoPhillips shall conduct, in accordance with Section III.A.2, a Method 9 Opacity test to monitor compliance with Section III.B.5 (ARM 17.8.1213).

B.20. As required by the Department and Section III.A.1, ConocoPhillips shall conduct, in accordance with Section III.A.2, a Method 5 Particulate Matter test or other Department approved test to monitor compliance with Section III.B.6 (ARM 17.8.1213).

B.21. 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 and Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (ARM 17.8.340; and 40 CFR 60, Subpart Db and Subpart Dc).

B.22. ConocoPhillips shall maintain a log of any instance when the ULNB is not operated on boilers B-5 and B-6, as required by Section III.B.9, including the date, duration, circumstance, and operators initials (ARM 17.8.1213).

B.23. ConocoPhillips shall test boilers B-5 and B-6 for NO_X and CO, both pollutants concurrently, and monitor compliance with the NO_X and CO emission limits contained in Sections III.B.10 & B.11. 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).

B.24. ConocoPhillips shall install and operate NO_x, CO, and oxygen (O_2) CEMS to monitor compliance with the emission limitations for boilers B-5 and B-6 (ARM 17.8.340 and 40 CFR 60, Subpart Db, ARM 17.8.342 and 40 CFR 63, Subpart DDDDD, "State Only", and ARM 17.8.749).

B.25. NO_x, CO, and O_2 CEMS shall be required to comply with quality assurance/quality control procedures in 40 CFR 60, Appendix F and operated in accordance with the performance specifications in 40 CFR 60, Appendix B, Performance Specification 2, 3 & 4 (40 CFR 60.13 and ARM 17.8.749).

B.26. ConocoPhillips shall monitor compliance with the VOC limit for the boilers B-5 and B-6 listed in Section III.B.12 by maintaining records of the fuel gas consumed and using an emission factor, as approved by the Department (ARM 17.8.1213).

B.27. ConocoPhillips shall monitor compliance with the temporary boiler requirements listed in Section III.B.14 by maintaining records of any instances when a temporary boiler is brought on-site. The records will include the date, duration of use, status of facility operations, fuel, and firing rate of the temporary boiler (ARM 17.8.1213).

Recordkeeping

B.28. All source testing recordkeeping shall be performed in accordance with the test method being used and Section III.A.2 (ARM 17.8.106).

B.29. Recordkeeping compiled for purposes of monitoring compliance with emission limitations shall be retained by ConocoPhillips for a minimum of 5 years (ARM 17.8.1212).

B.30. CEMS data shall be recorded by a data collections system and shall be maintained under ConocoPhillips's control for at least 5 years after the date of data generation. This electronic data shall be made available to Department personnel upon request and shall be submitted to the Department upon request (ARM 17.8.1212).

B.31. ConocoPhillips shall keep all records as required by 40 CFR 60, Subpart Db and Subpart Dc, as applicable (ARM 17.8.340 and 40 CFR 60, Subpart Db and Subpart Dc).

B.32. ConocoPhillips shall keep all applicable records as required by 40 CFR 60, Subpart J (ARM 17.8.340 and 40 CFR 60, Subpart J).

B.33. ConocoPhillips shall maintain records as required in Section III.B.24, III.B.28, and III.B.29 (ARM 17.8.1212).

Reporting

B.34. All source test reports shall be submitted to the Department in accordance with Section III.A.2 (ARM 17.8.106).

B.35. ConocoPhillips shall notify the Department in writing of each source test or RATA a minimum of 25 working days prior to the actual testing, unless otherwise specified by the Department (Billings/Laurel SO_2 Emission Control Plan, approved into the SIP by EPA on May 2, 2002).

B.36. In accordance with Section 7 of the Stipulation, ConocoPhillips shall submit quarterly reports within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to the Department's Permitting and Compliance office in Helena and the Billings Regional Office. The quarterly report format shall consist of both a comprehensive electronic-magnetic report and a written or hard copy data summary report (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

B.37. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1212).

B.38. The semiannual reporting shall provide (ARM 17.8.1212):

a. A summary of the results of any source tests performed during the period;

b. Reports of any required monitoring performed during the reporting period, with all instances of deviations from any permit requirements and corrective actions identified;

c. Certification that quarterly CEMS reports were submitted as required by Section III.B.38;

d. Certification that compliance with 40 CFR 60, Subpart Db and Subpart Dc was maintained; and

e. Certification that compliance with 40 CFR 60, Subpart J was maintained.

C. EU002 – FCCU

FCCU Regenerator

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
C.1, C.13, C.25, C.31 & C.32	FCCU	40 CFR 60, Subpart J	40 CFR 60, Subpart J	40 CFR 60, Subpart J	Semiannually
C.2, C.14, C.26, C.31 & C.32	FCCU	40 CFR 63, Subpart UUU	40 CFR 63, Subpart UUU	40 CFR 63, Subpart UUU	
C.3, C.4, C.5, C.6, C.15, C.17, C.18, C.22, C.23, C.24, C.27 – C.32	FCCU: SO_2	1440 ton/yr 3.945 ton/day 328.8 lb/hr on a rolling 24-hour average basis	CEMS	Ongoing	Quarterly
			Method 6/6C	Annually	Semiannually
		986.4 lb/3-hr 7,891.2 lb/cal. day 2,880,288 lb/cal. yr	CEMS	Ongoing	Quarterly
			Method 6/6C	Annually	Semiannually
		25 ppmvd/rolling 365-day average 50 ppmvd/rolling 7-day average	CEMS	Ongoing	Quarterly
			Method 6/6C	Annually	Semiannually
		20 lb/ton coke burnoff or fresh feed total sulfur <0.3% wt	CEMS	Ongoing	Quarterly
			Method 6/6C	Annually	
		Alternate Operating Scenario	Title V Appendix G	Ongoing	
C.7, C.8, C.15, C.17, C.19, C.22, C.23, C.24, C.27, C.28, C.31 & C.32	FCCU: CO	150 ppmvd/rolling 365-day	CEMS	Ongoing	Semiannually
		500 ppmvd/one hour average	Method 10	Annually	
C.9, C.16, C.17, C.22, C.24, C.27, C.30 & C.32	FCCU: NOx	49.2 ppmvd @ 0% O_2 365-day rolling average; and 69.5 ppmvd @ 0% O_2 7-day rolling average	CEMS	Ongoing	Quarterly
			RATA Method 7E	Annually	
C.10, C.15, C.17, C.22, C.23, C.24, C.27, C.28, C.31 & C.32	FCCU: Opacity	30% except for one six-minute average in any one hour period.	COMS	Ongoing	Semiannually
			Method 9	As required by the Department and Section III.A.1	
C.11, C.20, C.22, C.23, C.27, C.28, C.31 & C.32	PM, Industrial Processes	$E= 4.10 * P^{0.67}$ or $E= 55 * P^{0.11} - 40$	Method 5	As required by the Department and Section III.A.1	
C.12, C.21, C.22, C.23, C.27, C.28, C.31 & C.32	FCCU: PM	1 lb/1000 lb coke burned	Method 5	Annually, unless otherwise authorized	

Conditions

C.1. ConocoPhillips shall comply with all applicable requirements of 40 CFR 60, Subpart J-Standards of Performance for Petroleum Refineries. The FCCU is subject to the Subpart J requirements for opacity, PM, CO and SO_2 (Consent Decree; ARM 17.8.340; and 40 CFR 60, Subpart J).

C.2. ConocoPhillips shall comply with all applicable requirements of 40 CFR 63, Subpart UUU-National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. The FCCU is subject to the Subpart UUU requirements, including the requirement to prepare an Operation, Maintenance, and Monitoring Plan (OMMP) according to the requirements in 40 CFR 63.1574 and operate at all times according to the procedures in the plan (ARM 17.8.342; and 40 CFR 63, Subpart UUU).

C.3. SO_2 emissions from the FCCU are limited to 1440 ton/yr, 3.945 ton/day, and 328.8 lb/hr, calculated on a rolling 24-hour average (ARM 17.8.749 and ARM 17.8.1211).

C.4. SO_2 emissions from the FCCU are limited to 986.4 pounds per 3-hour period, 7,891.2 pounds per calendar day, and 2,880,288 pounds per calendar year (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

C.5. 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 hydrotreater outages at the Billings Refinery or during startup, shutdown or malfunction of the FCCU, or during periods of malfunction of a control system or pollutant-reducing catalyst additive system, provided that ConocoPhillips is maintaining and operating its FCCU (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 (see Appendix G of this permit) (Consent Decree, ARM 17.8.749).

C.6. SO_2 emissions from the 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) (Consent Decree, ARM 17.8.749, ARM 17.8.340 and 40 CFR 60, Subpart J).

C.7. CO emissions from the FCCU shall not exceed 150 ppmvd at 0% O_2 based on a rolling 365-day average basis (Consent Decree, ARM 17.8.749).

C.8. CO emissions from the FCCU shall not exceed 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 (Consent Decree, ARM 17.8.749).

C.9. NO_x emissions shall not exceed 49.2 ppmvd corrected to 0% O_2, on a rolling 365-day average and 69.5 ppmvd, corrected to 0% O_2, on a rolling 7-day average. The 7-day NO_x emission limit shall not apply during periods of hydrotreater outages at the Billings Refinery or during startup, shutdown or malfunction of the FCCU, or during periods of malfunction of a control system or pollutant-reducing catalyst additive system, provided that ConocoPhillips is maintaining and operating the FCCU (including associated air pollution control equipment) in a manner consistent with good air pollution control practices for minimizing emissions in accordance with the EPA-approved good air pollution control practices plan. For days in which the FCCU is not operating, no NOx value shall be used in the average, and those periods shall be skipped in determining the 7-day and 365-day averages (ConocoPhillips Consent Decree, Paragraph 27, as amended).

C.10. ConocoPhillips shall not cause or authorize emissions to be discharged into the outdoor atmosphere from the FCCU that exceed an opacity of 30% except for one six-minute average in any one hour period (Consent Decree, ARM 17.8.340 and 40 CFR 60, Subpart J).

C.11. ConocoPhillips shall not cause or authorize particulate matter to be discharged from any operation, process, or activity into the outdoor atmosphere in excess of the maximum hourly allowable emissions of particulate matter, calculated using the following equations:

For process weight rates up to 30 tons per hour: $E = 4.10 * P^{0.67}$

For process weight rates in excess of 30 tons per hour: $E = 55.0 * P^{0.11} – 40$

Where E is the rate of emissions in pounds per hour and P is the process weight rate in tons per hour (ARM 17.8.310).

C.12. ConocoPhillips shall not cause or authorize the FCCU to exceed the PM limit of 1 lb PM/1000 lb coke burned (Consent Decree, ARM 17.8.340, and 40 CFR 60, Subpart J).

Compliance Demonstration

C.13. 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 (Consent Decree; ARM 17.8.340; and 40 CFR 60, Subpart J).

C.14. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which reference 40 CFR 63, Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, including maintaining records to document conformance with procedures in ConocoPhillip's required OMMP (ARM 17.8.742 and 40 CFR 63, Subpart UUU).

C.15. The FCCU stack must be equipped and operated with CEMS and Continuous Opacity Monitoring System (COMS) to measure SO_2, CO, O_2, volumetric flow, and opacity. The monitoring system shall meet all performance specifications, methods, and procedures. The CEMS shall meet the performance specifications in 40 CFR 60, Appendix B, Performance Specification 1, 2, 3, 4/4A/4B, and 6, and the quality assurance/quality control requirements of 40 CFR 60, Appendix F ((ARM 17.8.749 and ARM 17.8.1211), (ARM 17.8.103(d) and 40 CFR 51, Appendix P), and (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002)).

C.16. The FCCU stack must be equipped and operated with CEMS to measure NOx. Emission monitoring shall be subject to 40 CFR 60, Appendix B (Performance Specifications 2 and 3 and Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.749 and ARM 17.8.1211).

C.17. Compliance with the emission limitations contained in Section III.C.3 to III.C.10 shall be monitored using data from the CEMS, COMS, and other Department-approved sampling methods (ARM 17.8.749 and ARM 17.8.1211).

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. Opacity compliance may also be monitored, via EPA reference Method 9, by a certified observer or monitor.

c. Other stack testing may include, but is not limited to, the following air pollutants: SO_2, NO_x, NH_3, CO, NOx, PM, PM_{10}, and VOCs.

d. Reporting requirements shall be consistent with 40 CFR Part 60, or as specified by the Department. CEMS data and calculations shall be submitted to the Department on a quarterly basis.

e. All gaseous (SO_2 and CO) CEMS shall be required to comply with quality assurance/quality control procedures in 40 CFR Part 60, Appendix F. SO_2 CEMS shall be required to be maintained such that it is available and operating at least 90% of the source operating time during any reporting period (quarterly).

f. CEM systems 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 CEM system 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 monitored. The Department shall approve such contingency plans.

g. In the case of GOHDS outages, as described in Section III.C.5, ConocoPhillips will maintain records of actions taken by ConocoPhillips to conform to the GOHDS Outage Plan (see Appendix G of this permit).

C.18. In order to accurately monitor the SO_2 emission rates in lb/hr for the FCCU Stack, ConocoPhillips shall perform annual source testing using EPA-approved methods (40 CFR Part 60, Appendix A, Methods 1-4 and 6/6C as appropriate for the Stipulation (STIP) and Exhibit A) or an equivalent method approved by the Department and EPA, and in accordance with Section III.A.1 of this permit (ARM 17.8.106).

The annual RATAs required by Section 6(C) and (D) of the STIP may be substituted for the annual source tests, provided that the flow rate RATA and the concentration RATA are performed simultaneously or concurrently and additional calculations are made to determine and report the data in lb/hr of SO_2 (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

C.19. In accordance with Section III.A.1 and as required by the Department, ConocoPhillips shall perform Method 10 or other Department approved testing, to monitor compliance with CO limitations in Section III.C.7 – C.8. The annual RATA may be substituted for the required source test (ARM 17.8.1213).

C.20. In accordance with Section III.A.1 and as required by the Department, ConocoPhillips shall perform Method 5 testing or other Department approved testing on the FCCU stack, to monitor compliance with PM limitations in Section III.C.10 (ARM 17.8.1213).

C.21. 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 monitor compliance with the PM limitations listed in Section III.C.11. After the life of the Consent Decree, ConocoPhillips shall conduct a PM stack test annually, unless another testing schedule is approved by the Department (Consent Decree, ARM 17.8.749).

Recordkeeping

C.22. All source test recordkeeping shall be performed in accordance with the test method being used and Section III.A.2 (ARM 17.8.106).

C.23. Recordkeeping compiled for purposes of monitoring compliance with emission limits shall be retained by ConocoPhillips for a minimum of 5-years (ARM 17.8.1212).

C.24. CEMS data shall be recorded by a data collections system and shall be maintained under ConocoPhillips's control for at least 5-years after the date of data generation. This electronic data shall be made available to Department personnel upon request and shall be submitted to the Department upon request (ARM 17.8.1212).

C.25. ConocoPhillips shall keep all records as required by 40 CFR 60, Subpart J (ARM 17.8.340 and 40 CFR 60, Subpart J).

C.26. ConocoPhillips shall keep all records as required by 40 CFR 63, Subpart UUU (ARM 17.8.342 and 40 CFR 63, Subpart UUU).

Reporting

C.27. All source test reports shall be submitted to the Department in accordance with Section III.A.2 (ARM 17.8.106).

C.28. ConocoPhillips shall notify the Department in writing of each source test or RATA a minimum of 25 working days prior to the actual testing, unless otherwise specified by the Department (Billings/Laurel SO_2 Emission Control Plan, approved into the SIP by EPA on May 2, 2002).

C.29. In accordance with Section 7 of the Stipulation, ConocoPhillips shall submit quarterly reports within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to the Department's Permitting and Compliance office in Helena and the Billings Regional Office. The quarterly report format shall consist of both a comprehensive electronic-magnetic report and a written or hard copy data summary report (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

C.30. ConocoPhillips shall report quarterly, the daily NOx rolling 365-day average and the maximum NOx 7-day rolling average per quarter for the FCCU stack. These reports shall also include NOx CEMS quarterly performance (excess emissions and monitor downtime) and Appendix F (Quality Assurance and Quality Control) provisions. FCCU quarterly NOx reporting shall be submitted in conjunction with the SO_2 SIP emissions and CEMS/CERMS reporting periods (ARM 17.8.1212).

C.31. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1212).

C.32. The semiannual reporting shall provide (ARM 17.8.1212):

a. A summary of the results of any source tests performed during the period;

b. Reports of any required monitoring performed during the reporting period, with all instances of deviations from any permit requirements and corrective actions identified;

c. Certification that quarterly CEMS reports were submitted as required by Section III.C.27;

d. Certification that compliance with 40 CFR 60, Subpart J was maintained; and

e. Certification that compliance with 40 CFR 63, Subpart UUU was maintained.

D. EU003 –Refinery Fuel Gas Combustion Units

"22-Fuel-Gas-Heater Source": 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-23, H-24, Coker Heater: H-3901, Recycle Hydrogen Heater: H-8401, Fractionator Heater: H-8402

Additional Refinery Fuel Gas combustion sources:
No. 1 H_2 Unit Reformer Heater: H-9401,
No. 5 HDS Recycle (Charge Heater): H-9501,
No. 5 HDS Fractionator (Stabilizer) Reboiler: H-9502, and
No. 2 H_2 Unit Reformer Heater: H-9701

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
D.1, D.19, D.31, D.34, D.41 & D.42	Fuel combustion	No fuel oil combusted	Log	Ongoing	Semiannually
D.2, D.3, D.20, D.21, D.23, D.24, D.32, D.35, D.37-D.42	SO_2	22-Fuel-Gas-Heater Source: 45.5 ton/yr, 614 lb/day	Method 6/6C	As required by the Department and Section III.A.1	Semiannually
			CEMS	Ongoing	Quarterly
		87.0 lb/3-hr 696.0 lb/Cal. Day 254,040 lb/Cal. yr	Method 6/6C	As required by the Department and Section III.A.1	Semiannually
			CEMS	Ongoing	Quarterly
D.4, D.21, D.24, D.36, D.41 & D.42	Refinery Fuel Gas	40 CFR 60, Subpart J	40 CFR 60, Subpart J	40 CFR 60, Subpart J	40 CFR 60, Subpart J
D.5, D.6, D.24, D.25, D.32, D.35, D.37 – D.42	H_2S	0.10 grains/dscf on a 3-hour basis	Method 11	Annually	Semiannually
			CEMS	Ongoing	Quarterly
D.7, D.24, D.25, D.32, D.35, D.37 – D.42	H_2S - specific process heaters	0.073 gr/dscf (116.5 ppmv H_2S) per rolling 12-months	Method 11	Annually	Semiannually
			CEMS	Ongoing	Quarterly
D.8, D.24, D.25, D.32, D.37, D.38, D.41 & D.42	PSA purge gas	Sulfur free purge gas	Method 11	As required by the Department and Section III.A.1	Semiannually
D.9, D.26, D.32, D.37, D.38, D.41 & D.42	NO_x – Coker Furnace	0.08 lb/MMBtu 7.38 lb/hr	Method 7	As required by the Department and Section III.A.1	
			Low NO_x burners	Ongoing	

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
	NO_x – Other Furnaces	0.03 lb/MMBtu	Method 7	As required by the Department and Section III.A.1	Semiannually
			ULNB or Low NOx burners w /FGR	Ongoing	
D.10, D.26, D.32, D.37, D.38, D.41 & D.42	Total NO_x – - Coker Heater, - Recycle Hydrogen Heater, - Fractionator Feed Heater and - No. 1 H_2 Unit Reformer Heater	13.54 lb/hr, 58.95 ton/yr	Method 7	As required by the Department and Section III.A.1	
			Ultra Low and Low NO_x burners	Ongoing	
D.11, D.26, D.32, D.37, D.38, D.41 & D.42	Total NO_x – - No.5 HDS Charge Heater, - No.5 HDS Stabilizer Reboiler Heater, and - No.2 H_2 Unit Reformer Heater	7.95 lb/hr, 34.19 ton/yr	Method 7	As required by the Department and Section III.A.1	
			Ultra Low and Low NO_x burners	Ongoing	
D.12, D.13, D.14, D.27, D.33, D.34, D.41 & D.42	NO_x Control	Low NO_x burners, Ultralow NO_x burners, and FGR	Log	Monthly inspections and any maintenance	
D.15, D.28, D.32, D.37, D.38, D.41 & D.42	CO – - No.2 H_2 Unit Reformer Heater, - No.5 HDS Stabilizer Reboiler Heater, and - No.5 HDS Charge Heater	Various	Method 10	As required by the Department and Section III.A.1	
D.16, D.17, D.29, D.32, D.37, D.38, D.41 & D.42	Opacity	40% / 20%	Method 9		
D.18, D.30, D.32, D.37, D.38, D.41 & D.42	Particulate Matter, Fuel Burning	$E= 0.882 * H^{-0.1664}$ or $E= 1.026 * H^{-0.233}$	Method 5		

Conditions

D.1. ConocoPhillips shall not burn fuel oil in any of its heaters (ARM 17.8.749).

D.2. ConocoPhillips may not cause or authorize SO_2 emissions from the "22-Fuel-Gas-Heater" source in excess of 614 lb/day on a rolling 24-hour average or 45.5 ton/year on a rolling 12-month average (ARM 17.8.749 and ARM 17.8.1211).

D.3. Combined emissions of SO_2 for the process heaters shall not exceed 87.0 pounds per 3-hour period, 696.0 pounds per calendar day, 254,040 pounds per calendar year (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

D.4. ConocoPhillips shall comply with all applicable requirements of 40 CFR 60, Subpart J-Standards of Performance for Petroleum Refineries, as it applies to fuel gas combustion devices. All process heaters used to combust RFG at ConocoPhillips are fuel gas combustion devices and are considered "affected facilities" under 40 CFR 60, Subparts A and J. Fuel-fired equipment exclusively burning natural gas are not "fuel gas combustion devices" and are not "affected facilities" under 40 CFR 60, Subparts A and J during such periods (Consent Decree, ARM 17.8.749, ARM 17.8.340 and 40 CFR 60, Subpart J).

D.5. Except for periods of startup, shutdown, and malfunction, ConocoPhillips shall not burn in any fuel gas combustion device any fuel gas that contains H_2S in excess of 230 mg/dscm (0.10 gr/dscf, or ~160 ppmvd) per rolling 3-hour period (Consent Decree, ARM 17.8.749, ARM 17.8.340 and 40 CFR 60, Subpart J).

D.6. H_2S content of the fuel gas burned in the RFG Heaters/Furnaces shall not exceed 0.10 grains/dscf on a 3-hour basis (ARM 17.8.749, ARM 17.8.1211, ARM 17.8.340, and 40 CFR 60, Subpart J).

D.7. H_2S content of fuel gas shall not exceed 0.073 gr/dscf (116.5 ppmv H_2S) per rolling 12-month time period, for fuel gas burned in (ARM 17.8.749):
- H-10, No. 2 HDS
- H-11, Debutanizer Reboiler, No. 2 HDS
- H-12, Main Frac. Reboiler No. 2 HDS
- H-13, Catalytic Reforming Unit #2
- H-14, Catalytic Reforming Unit #2
- H-16, Stabilizer Reboiler, Sat Gas
- H-23, Catalytic Reforming Unit #2
- H-9401, No.1 H_2 Unit Reformer Heater
- H-9701, No.2 H_2 Unit Reformer Heater
- H-9501, No.5 HDS Charge Heater
- H-9502, No.5 HDS Stabilizer Reboiler Heater

D.8. The Pressure Swing Adsorption (PSA) purge gas, used as furnace fuel for the No.2 H_2 Unit Reformer Heater (H-9701), shall be sulfur free (ARM 17.8.752 and ARM 17.8.1211).

D.9. NO_x emissions shall not exceed the limit of (ARM 17.8.752 and ARM 17.8.1211):
- Coker Heater (H-3901)- 0.08 lb/MMBtu and 7.38 lb/hr
- Recycle Hydrogen Heater (H-8401) - 0.03 lb/MMBtu
- Fractionator Feed Heater (H-8402) - 0.03 lb/MMBtu
- No. 1 H_2 Unit Reformer Heater (H-9401) - 0.03 lb/MMBtu
- No. 2 H_2 Unit Reformer Heater (H-9701) – 0.03 lb/MMBtu per rolling 12-month
- No. 5 HDS Charge Heater (H-9501) – 0.03 lb/MMBtu per rolling 12-month
- No. 5 HDS Stabilizer Reboiler Heater (H-9502) – 0.03 lb/MMBtu per rolling 12-month

D.10. The total NO_x emissions from the Coker Heater (H-3901), Recycle Hydrogen Heater (H-8401), Fractionator Feed Heater (H-8402), and No. 1 H_2 Unit Reformer Heater (H-9401) shall not exceed the limit of 13.54 lb/hr and 58.95 ton/yr (ARM 17.8.749, ARM 17.8.752, and ARM 17.8.1211).

D.11. 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 Unit Reformer Heater (H-9701) shall not exceed 7.95 lb/hr and 34.19 tons/year (ARM 17.8.752 and ARM 17.8.1211).

D.12. ConocoPhillips shall equip and maintain low NO_x burners on the Coker Heater (H-3901) (ARM 17.8.749 and ARM 17.8.1211).

D.13. ConocoPhillips shall equip and maintain ULNB on the Recycle Hydrogen Heater (H-8401), Fractionator Feed Heater (H-8402), No. 5 HDS Charge Heater (H-9501), No. 5 HDS Stabilizer (Fractionator) Reboiler Heater (H-9502), and No. 2 H_2 Plant Reformer Heater (H-9701) (ARM 17.8.749, ARM 17.8.752, and ARM 17.8.1211).

D.14. ConocoPhillips shall equip and maintain low NO_x burners and Flue Gas Recirculation (FGR) on the No. 1 H_2 Plant Heater (H-9401) (ARM 17.8.749 and ARM 17.8.1211).

D.15. CO emissions shall not exceed the limit of (ARM 17.8.752 and ARM 17.8.1211):
- No. 2 H_2 Unit Reformer Heater (H-9701) – 0.025 lb/MMBtu per rolling 12-month
- No. 5 HDS Charge Heater (H-9501) – 0.317 lb/MMBtu per rolling 12-month when heater is operating at 10.9 MMBtu/hr or less, and 0.1585 lb/MMBtu per rolling 12-month when heater is operating at 10.9 MMBtu/hr or more
- No. 5 HDS Stabilizer Reboiler Heater (H-9502) – 0.1585 lb/MMBtu per rolling 12-month when heater is operating at 29.9 MMBtu/hr or less and 0.091 lb/MMBtu per rolling 12-month when heater is operating at 29.9 MMBtu/hr or more

D.16. Opacity from any of the RFG Heaters/Furnaces constructed prior to 1968 (including but not limited to 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-23, H-24) shall not exceed 40% averaged over any 6 consecutive minutes (ARM 17.8.304(1)).

D.17. Opacity from any of the RFG Heaters/Furnaces constructed after1968 (including but not limited to H-1, No. 5 HDS Charge Heater, No. 5 HDS Stabilizer Reboiler Heater, No. 2 H_2 Unit Reformer Heater, Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heater, shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304(2)).

D.18. ConocoPhillips shall not cause or authorize particulate matter caused by the combustion of fuel to be discharged from any stack or chimney into the outdoor atmosphere in excess of the maximum allowable emissions of particulate matter for existing fuel burning equipment and new fuel burning equipment, calculated using the following equations:

For existing fuel burning equipment (installed before November 23, 1968):
$E = 0.882 * H^{-0.1664}$

For new fuel burning equipment (installed on or after November 23, 1968):
$E = 1.026 * H^{-0.233}$

Where H is the heat input capacity in MMBtu per hour and E is the maximum allowable particulate emissions rate in pounds per MMBtu (ARM 17.8.309).

Compliance Demonstration

D.19. ConocoPhillips shall log any instance in which fuel oil was combusted in any of the Process Heaters for the period, including the date, duration, circumstance, and operators initials (ARM 17.8.1213).

D.20. As required by the Department and Section III.A.1, ConocoPhillips shall perform source testing on the fuel gas combustion units using Method 6/6C or other Department approved test methods, to monitor compliance with the SO_2 limitations in Section III.D.2 and III.D.3 (ARM 17.8.1213).

D.21. ConocoPhillips shall conduct all monitoring and testing as required by 40 CFR 60, Subpart J, Standards of Performance for Petroleum Refineries, to monitor compliance with Section III.D.2 – III.D.8. ConocoPhillips shall install, calibrate, maintain, and operate a H_2S CEMS to continuously monitor and record the concentration (dry basis) of H_2S in the RFG before being burned in any fuel gas combustion device, or develop an Alternate Monitoring Plan (AMP), as required by 40 CFR 60, Subparts A and J. Compliance with the fuel gas H_2S concentration limits shall be monitored based on 3-hour rolling average H_2S concentrations, determined by utilizing data taken from the CEMS and other Department-approved sampling methods.

The H_2S CEMS shall be installed, certified, and operated in accordance with Performance Specification 7 (40 CFR 60, Appendix B) to meet applicable provisions of 40 CFR 60.105(a)(4), 60.7, and 60.13. The H_2S CEMS shall meet the quality assurance and quality control requirements set out in 40 CFR 60, Appendix F (annual RATA), as provided by the SO_2 Stipulation. The CEMS shall meet applicable quarterly data recovery rates and other provisions of §6(A) of the SO_2 Stipulation (ARM 17.8.340 and 40 CFR 60, Subpart J; Consent Decree; Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, ARM 17.8.1212, and ARM 17.8.1213).

D.22. ConocoPhillips shall operate and maintain a continuous flow rate monitor on the RFG header. Accuracy determinations for the RFG flow rate monitor shall be required at least once every 48 months or more frequently as routine refinery turn-arounds allow (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

D.23. Compliance with the SO_2 emission limitation for the RFG fired units, contained in Section III.D.2 and III.D.3, shall be monitored by using hourly average H_2S concentration and hourly average fuel gas flow rate data from the CEMS and in accordance with the appropriate equations contained in the SIP (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

D.24. Compliance with Section III.D.2 – III.D.8 shall be monitored by utilizing valid data taken from CEMS and other Department approved sampling methods (ARM 17.8.749 and ARM 17.8.1211).

a. The above does not relieve ConocoPhillips from meeting any applicable requirements of 40 CFR Part 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, NH_3, CO, particulate matter (PM, PM_{10}), and VOCs.

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

d. All gaseous (SO_2 and H_2S) CEMS shall be required to comply with quality assurance/quality control procedures in 40 CFR Part 60, Appendix F. Said CEMS shall be required to be maintained such that it is available and operating at least 90% of the source operating time during any reporting period (quarterly).

e. CEM systems 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 CEM system 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 monitored. The Department shall approve such contingency plans.

D.25. In order to accurately determine the H_2S concentration in parts per million for the fuel gas-system, ConocoPhillips shall perform annual source testing using, EPA-approved methods (40 CFR Part 60, Appendix A, Method 11) or an equivalent method approved by the Department and EPA, and in accordance with Section III.A.2 of this permit (ARM 17.8.106) (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

D.26. As required by the Department and Section III.A.1, ConocoPhillips shall perform source testing on the fuel gas combustion units using Method 7 or other Department approved test methods to monitor compliance with the NO_x emission limitations in Section III.D.9, III.D.10, and III.D.11 (ARM 17.8.1213).

D.27. Compliance with Sections III.D.12, III.D.13, and III.D.14 shall be monitored by monthly inspection of the FGR, Ultra Low and Low NO_x burners to confirm they are properly installed and operating on the fuel gas combustion units. Utilization of these low NO_x technologies shall monitor compliance with the NO_x emission limitations in Sections III.D.9, III.D.10, and III.D.11 (ARM 17.8.1213).

D.28. As required by the Department and Section III.A.1, ConocoPhillips shall perform source testing on the fuel gas combustion units using Method 10 or other Department approved test methods, to monitor compliance with the CO limitation in Section III.D.15 (ARM 17.8.1213).

D.29. As required by the Department and Section III.A.1, ConocoPhillips shall perform source testing on the fuel gas combustion units using Method 9 to monitor compliance with Section III.D.16 and III.D.17 (ARM 17.8.1213).

D.30. As required by the Department and Section III.A.1, ConocoPhillips shall perform source testing on the fuel gas combustion units using Method 5 or other Department approved test methods, to monitor compliance with Section III.D.18 (ARM 17.8.1213).

Recordkeeping

D.31. ConocoPhillips shall maintain, under ConocoPhillips's control, a log of fuel oil consumption as required in Section III.D.20 (ARM 17.8.1212).

D.32. All source testing recordkeeping shall be performed in accordance with the appropriate test method being used and Section III.A.2 (ARM 17.8.106).

D.33. ConocoPhillips shall maintain, under ConocoPhillips's control, a log of monthly inspection and any maintenance performed on the Ultra Low and Low NO_x burners (ARM 17.8.1212).

D.34. ConocoPhillips shall maintain, under ConocoPhillips's control, all logs required for monitoring compliance, shall make all logs available to Department personnel during inspections, and shall submit the logs to the Department upon request (ARM 17.8.1212).

D.35. CEMS data shall be recorded by a data collections system and shall be maintained under ConocoPhillips's control for at least 5-years after the date of data generation. This electronic data shall be made available to Department personnel upon request and shall be submitted to the Department upon request (ARM 17.8.1212).

D.36. ConocoPhillips shall keep all records as required by 40 CFR 60, Subpart J (ARM 17.8.340 and 40 CFR 60, Subpart J).

Reporting

D.37. All source test reports shall be submitted to the Department in accordance with Section III.A.2 (ARM 17.8.106).

D.38. ConocoPhillips shall notify the Department in writing of each source test or RATA a minimum of 25 working days prior to the actual testing, unless otherwise specified by the Department (Billings/Laurel SO_2 Emission Control Plan, approved into the SIP by EPA on May 2, 2002).

D.39. In accordance with Section 7 of the Stipulation, ConocoPhillips shall submit quarterly reports within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to the Department's Permitting and Compliance office in Helena and the Billings Regional Office. The quarterly report format shall consist of both a comprehensive electronic-magnetic report and a written or hard copy data summary report (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

D.40. ConocoPhillips shall provide quarterly emission reports from said emission rate monitors. Emission reporting for SO_2 from all point source locations shall consist of 24-hour calendar day totals per calendar month. The quarterly report shall also include the following (ARM 17.8.749 and ARM 17.8.1211):

a. Source or unit operating times during the reporting period;

b. Monitoring down time which occurred during the reporting period;

c. A summary of excess emissions for each pollutant and averaging period identified in Section III.D.2 through III.D.8; and

d. Reasons for any emissions in excess of those specifically allowed in Section III.D.2 through III.D.8 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the upset situation.

ConocoPhillips shall submit quarterly emission reports within 30 days of the end of each calendar quarter.

D.41. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1212).

D.42. The semiannual reporting shall provide (ARM 17.8.1212):

a. A summary of results of any source testing that was performed during the period;

b. Reports of any required monitoring performed during the reporting period, with all instances of deviations from any permit requirements and corrective actions identified;

c. Certification that quarterly reports of CEMS data were submitted as required by Section III.D.42; and

d. Certification that compliance with 40 CFR 60, Subpart J was maintained.

E. EU005 – Refinery Main Plant Relief Flare

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
E.1, E.2, E.3, E.4 E.5, E.8, E.9, E.10, E.12, E.13, E.14, E.15, E.18 – E.22	SO_2	40 CFR 60, Subpart J: Minimize SO_2 flaring by operating with flare gas recovery system	Log	Ongoing	At least Quarterly & as necessary
		Minor Flaring, and 150 lb/3-hr	Reporting & Corrective Action		
		Flaring 500 lbs/24-hr	RCFA and corrective action		
		Offset SO_2 emissions	Log		Semiannually
E.6, E.11, E.17, E.21 & E.22	Flare	Equipped and Operated with a Steam Injection System. Tip to Base: at least 142 +/- 2 feet above grade	Log	Ongoing	Semiannually
E.7, E.12, E.16, E.21 & E.22	Flow rate	Flow rate metering shall use approved standards, methods, accounting procedures, and engineering data	Log	Monthly	Quarterly

Conditions

E.1. 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; Consent Decree; Montana Consent Decree and ARM 17.8.1211).

E.2. ConocoPhillips shall not allow SO2 emissions from any flare, unless the emissions are a minor flaring event, or are the result of start-up, shutdown, or a malfunction as defined in ARM 17.8.110. A minor flaring event means a flaring event that emits less than or equal to 150 pounds of SO2 per 3-hour period (Board of Environmental Review Order signed on June 12, 1998, this requirement is "State Only").

E.3. Except for minor flaring events, ConocoPhillips shall minimize SO2 emissions from flaring. In addition, when flaring of sulfur bearing gases occurs due to a malfunction, ConocoPhillips shall take immediate action to correct the malfunction (Board of Environmental Review Order signed on June 12, 1998, this requirement is "State Only").

E.4. For any acid gas, hydrocarbon, or tail gas flaring incident that results in an emission of SO2 that is 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, Consent Decree and ARM 17.8.1211).

E.5. SO2 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 (ARM 17.8.749 and ARM 17.8.1211).

E.6. The Refinery Main Plant Relief Flare must be equipped and operated with a steam injection system. The flare tip height shall be a minimum of 142 feet plus or minus 2 feet above grade (ARM 17.8.749, ARM 17.8.752 and ARM 17.8.1211).

E.7. Any flow rate metering from upset or malfunctioning process units that are directed to either the Refinery Main Plant Relief flare or the SRU flare shall use approved standards, methods, accounting procedures, and engineering data (ARM 17.8.749 and ARM 17.8.1211).

Compliance Demonstration

E.8. 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 SO2 emissions which result from gases being directed to and combusted in the flare. 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 (ARM 17.8.1213).

E.9. For purposes of determining whether a flaring event greater than 150 pounds of SO2 per 3-hour period or 500 lbs in a 24-hour period has occurred, ConocoPhillips shall maintain records of all activities, other than de minimis activities, that result in SO2 emissions from the flare (Board of Environmental Review Order signed on June 12, 1998, this requirement is "State Only," Consent Decree, and ARM 17.8.1213).

E.10. ConocoPhillips shall maintain, under ConocoPhillips's control, a record of SO2 offsets as required by Section III.E.5 (ARM 17.8.1213).

E.11. ConocoPhillips shall maintain, under ConocoPhillips's control, a record of any changes made to the Refinery Main Plant Relief flare steam injection system or stack height, as required by Section III.E.6, including the date, duration, circumstance, and operators initials (ARM 17.8.1213).

E.12. ConocoPhillips shall provide quarterly emission reports for the Refinery Main Plant Relief flare SO2 emissions based on H2S concentration information and flow information. The quarterly emission reports shall be submitted within 30 days of the end of each calendar quarter. The quarterly report shall consist of 24-hour calendar day totals per calendar month and shall include the following (ARM 17.8.749 and ARM 17.8.1211):

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

b. Monitoring downtime that occurred during the reporting period;

c. A summary of excess emissions for each pollutant and averaging period; and

d. Emission estimates for SO_2, other than de minimis activities, from material balance, engineering calculation data, and any emission testing.

Recordkeeping

E.13. All source test reports shall be submitted to the Department in accordance with Section III.A.2 (ARM 17.8.106).

E.14. Recordkeeping compiled for purposes of demonstrating compliance with emission limits shall be retained by ConocoPhillips for a minimum of 5-years (ARM 17.8.1212).

E.15. ConocoPhillips shall maintain a record of all flaring events other than flaring caused by de minimis activities. Each entry shall include the date; time; duration; an engineering estimate of the 3-hour emissions and 24-hour emissions; the measured flow rate to the flare, if available; a description of the source and estimated equivalent sulfur content of the gases directed to the flare; a reason for the flaring event; a description of the immediate actions taken to correct the situation; and the operator's initials (Board of Environmental Review Order signed on June 12, 1998, this requirement is "State Only," and ARM 17.8.1213).

E.16. ConocoPhillips shall maintain, under ConocoPhillips's control, a log of the monthly inspection and maintenance performed on the flow rate-metering device used on upset or malfunctioning process units that are directed to either the Refinery Main Plant Relief flare or the SRU flare (ARM 17.8.1212).

E.17. The Refinery Main Plant Relief Flare recordkeeping shall be maintained as required in Section III.E.11 (ARM 17.8.1212).

E.18. ConocoPhillips shall keep all records as required by 40 CFR 60, Subpart J (ARM 17.8.340 and 40 CFR 60, Subpart J).

Reporting

E.19. For flaring events in excess of 150 lb/3-hr period, ConocoPhillips shall comply with the reporting requirements identified in Section (3)(A)(5) of Exhibit A-1 of the Stipulation (Board of Environmental Review Order Signed on June 12, 1998. This requirement is "State Only").

E.20. For flaring events in excess of 500 lb/24-hr period, ConocoPhillips shall prepare a RCFA and corrective action (ARM 17.8.749, Consent Decree and ARM 17.8.1211).

E.21. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1212).

E.22. The semiannual reporting shall provide (ARM 17.8.1212):

a. A summary of results of any source testing that was performed during the period;

b. Reports of any required monitoring performed during the reporting period, with all instances of deviations from any permit requirements and corrective actions identified.

c. Certification that quarterly reports were submitted as required by Section III.E.12; and

d. Certification that compliance with 40 CFR 60, Subpart J was maintained.

F. EU006 – Refinery Fugitive Emissions

C-23 Compressor Station, Delay Coker Unit, Cryogenic Unit, Hydrogen Membrane Unit, Gasoline Merox Unit, Crude Topping Unit, Crude Vacuum Unit, Fluidized Catalytic Cracking Unit, Catalytic Reforming Unit, Hydrodesulfurization Unit, Gas Oil Hydrotreater Unit (consisting of a reaction section, fractionation section, and an amine treating section), 20.0 MMscfd Hydrogen Plant Feed System, Alkylation Unit Butane Defluorinator (consisting of heat exchangers; X-453, X-223, X-450, X-451, X-452, pumps; P-646, Vessels; D-130, D-359, D-360), PMA Process Unit, Alkylation Unit Depropanizer, Cryo Debutanizer Unit, Butamer/Feed Prep Unit, Gas Recovery Plant Unit, Naphtha Splitter Unit, Sat Gas Plant Unit, Hydrogen Purification Unit, Railcar loading, Cooling Towers, and Tank Farm.

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
F.1, F.12, F.20, F.22 & F.23	Equipment Leaks	40 CFR 60, Subpart GGG	40 CFR 60, Subpart GGG	40 CFR 60, Subpart GGG	40 CFR 60, Subpart GGG
F.2, F.12, F.20, F.22 & F.23	Equipment Leaks	40 CFR 63, Subpart CC	40 CFR 63.654	40 CFR 63.654	40 CFR 63.654
F.3 – F.7, F.13, F.19, F.22 & F.23	All Valves	High quality with high quality packing.	Log	As purchased and installed	Semiannually
	Open-Ended Valves	High quality with high quality packing. Plugs, caps or a second valve on the open end.			
	Pipe and Tower Flanges	Compatible gasket material			
	Pumps	Mechanical seals			
	VOC monitoring and maintenance program	Monitoring & Maintenance Plan		During performance of program	
F.8, F.14, F.19, F.22 & F.23	Failure or leakage of compressor seal system	Repair		Each repair	
F.9, F.15, F.19, F.22 & F.23	Saturate Gas Plant	LDAR	40 CFR 60, Subpart VV	40 CFR 60, Subpart VV	
F.10, F.16, F.19, F.22 & F.23	LSG Project	LDAR	40 CFR 60, Subpart VV	40 CFR 60, Subpart VV	
F.11, F.17, F.18, F.21 – F.23	Haul Road PM Opacity	20%	Method 9	As required by the Department and Section III.A.1	

Conditions

F.1. ConocoPhillips shall comply with all applicable requirements of 40 CFR 60, Subpart GGG, including compliance with the applicable requirements contained in 40 CFR 60, Subpart VV (ARM 17.8.340 and 40 CFR 60, Subpart GGG).

F.2. ConocoPhillips shall comply with all applicable requirements of 40 CFR 63, Subpart CC, including compliance with the applicable requirements contained in 40 CFR 60, Subpart VV. In addition, ConocoPhillips shall comply with all applicable requirements of 40 CFR 63.648 as they apply to all units subject to 40 CFR 63, Subpart CC that are required to comply with the equipment leak regulations, including, but not limited to the Tank Farm, Large Crude/Vacuum Unit, Small Crude Unit, #1 & #2 Reformer Unit, #1 & #2 HDS Unit, Cryo Debutanizer Unit, Butamer/Feed Prep Unit, FCCU, Gas Recovery Plant Unit, Alkylation Unit, PB Merox Unit, Naphtha Splitter Unit, Sat Gas Plant Unit, and Hydrogen Purification Unit (ARM 17.8.342 and 40 CFR 63, Subpart CC).

F.3. All valves used in equipment subject to 40 CFR 60, Subpart GGG, as well as the C-23 Compressor station, shall be high quality valves containing high quality packing (ARM 17.8.340 and 40 CFR 60, Subpart GGG, ARM 17.8.752, and ARM 17.8.1211).

F.4. All open-ended valves used in equipment subject to 40 CFR 60, Subpart GGG, as well as the C-23 Compressor station, shall be high quality valves containing high quality packing. They will have plugs, caps, or a second valve installed on the open end (ARM 17.8.340 and 40 CFR 60, Subpart GGG, ARM 17.8.752, and ARM 17.8.1211).

F.5. All pipe and tower flanges used in equipment subject to 40 CFR 60, Subpart GGG, as well as the C-23 Compressor station, shall be installed using process compatible gasket material (ARM 17.8.340 and 40 CFR 60, Subpart GGG, ARM 17.8.752, and ARM 17.8.1211).

F.6. All pumps used in equipment subject to 40 CFR 60, Subpart GGG, as well as the C-23 Compressor station, shall be fitted with the highest quality state-of-the-art mechanical seals, as appropriate (ARM 17.8.340 and 40 CFR 60, Subpart GGG, ARM 17.8.752, and ARM 17.8.1211).

F.7. A VOC monitoring and maintenance program shall be instituted in equipment subject to 40 CFR 60, Subpart GGG, as well as the C-23 Compressor station, as described in 40 CFR 60.482-2, 40 CFR 60.482-4 through 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) (ARM 17.8.340 and 40 CFR 60, Subpart GGG, ARM 17.8.752, and ARM 17.8.1211).

F.8. If monitoring or scheduled inspections indicate failure or leakage of the C-23 compressor seal system, then the seals shall be repaired as soon as practicable, but not later than 15 days after it is detected, except as provided in 40 CFR 60.482-9 (ARM 17.8.752 and ARM 17.8.1211).

F.9. 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 (ARM 17.8.342, 40 CFR 63, Subpart CC and ARM 17.8.752).

F.10. 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).

F.11. All access roads shall use either paving or chemical dust suppression 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. Construction and earth-moving activities shall use reasonable precautions to limit excessive fugitive dust to mitigate impacts to nearby residential and commercial places (ARM 17.8.749, ARM 17.8.1211, and ARM 17.8.308).

Compliance Demonstration

F.12. Compliance monitoring for equipment leaks shall be performed in accordance with the applicable provisions of 40 CFR 60, Subpart VV and 40 CFR 63.654, 63.644, and/or 63.645, as appropriate (ARM 17.8.340 and 40 CFR 60, Subpart GGG and ARM 17.8.342 and 40 CFR 63, Subpart CC).

F.13. ConocoPhillips shall institute the monitoring and maintenance plan in accordance with 40 CFR 60, Subpart VV (ARM 17.8.340 and 40 CFR 60, Subpart GGG and ARM 17.8.342 and 40 CFR 63, Subpart CC).

F.14. ConocoPhillips shall maintain a log, under ConocoPhillips's control, of all leakage repairs associated with the C-23 compressor seal system. The log shall contain the date, time, repair personnel's initials and type of repair made (ARM 17.8.1213).

F.15. ConocoPhillips shall maintain records of the Saturate Gas Plant LDAR program, as described in Section III.F.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).

F.16. ConocoPhillips shall maintain records of the new LSG project LDAR program, as described in Section III.F.11. 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).

F.17. As required by the Department and Section III.A.1, ConocoPhillips shall perform a Method 9 opacity test on the haul roads to monitor compliance with the 20% opacity limitation as specified in Section III.F.13 (ARM 17.8.1213).

Recordkeeping

F.18. ConocoPhillips shall perform all source testing recordkeeping in accordance with the appropriate test method and Section III.A.2 (ARM 17.8.106).

F.19. ConocoPhillips shall maintain, under ConocoPhillips's control, all logs required for monitoring compliance, shall make all logs available to Department personnel during inspections, and shall submit the logs to the Department upon request (ARM 17.8.1212).

F.20. Recordkeeping for equipment leaks shall be performed in accordance with the applicable provisions of 40 CFR 60, Subpart VV and 40 CFR 63.654, 63.644, and/or 63.645, as appropriate (ARM 17.8.340 and 40 CFR 60, Subpart GGG and ARM 17.8.342 and 40 CFR 63, Subpart CC).

Reporting

F.21. ConocoPhillips shall submit all source test reports in accordance with Section III.A.2 (ARM 17.8.106).

F.22. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1212).

F.23. The semiannual reporting shall provide (ARM 17.8.1212):

a. A summary of the results of any source tests performed during the period;

b. Reports of any required monitoring performed during the reporting period, with all instances of deviations from any permit requirements and corrective actions identified;

c. Certification that compliance with 40 CFR 60, Subpart GGG was maintained; and

d. Certification that compliance with 40 CFR 63, Subpart CC was maintained.

G. EU007 – Sulfur Recovery Facility

- Ammonium Thiosulfate (ATS) Unit,
- Ammonium Sulfide Unit,
- Sulfur Recovery Unit (SRU), and
- Jupiter SRU Flare.

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
G.1, G.2, G.21, G.45, G.57 & G.58	Jupiter SRU Flare and Claus units	40 CFR 60, Subpart J	40 CFR 60, Subpart J	40 CFR 60, Subpart J	Semiannually
G.3, G.22, G.46, G.57 & G.58	Claus units	40 CFR 63, Subpart UUU	40 CFR 63, Subpart UUU	40 CFR 63, Subpart UUU	
G.4, G.23, G.49, G.53, G.57 & G.58	Jupiter SRU flare	Steam injection, flare height of 213 ft	Inspection & Maintenance Log	Ongoing	
G.5, G.6, G.24, G.47, G.56 – G.58	Jupiter SRU flare	Minor flaring and 150 lb/3-hr	Reporting and Corrective Action	As necessary	
G.7, G.25, G.48, G.49, G.57 & G.58	Flow rate	Flow rate metering shall use approved standards, methods, accounting procedures, and engineering data	Log	Quarterly	Quarterly
G.8, G.26, G.53, G.57 & G.58	SRU Incinerator	Equipped with low NO_x burners	Inspection & Log	Semiannually & annually	Semiannually
G.9, G.27, G.28, G.41, G.42, G.43, G.44, G.54, G.55, G.57 & G.58	SO_2 from SRU/ATS main stack	0.300 ton/day, 25.00 lb/hr	CEMS	Ongoing	
			Method 6/6C	Annually	
G.10, G.29, G.44, G.54, G.55, G.57 & G.58	NO_x from SRU/ATS main stack	82.85 ton/yr, 454.0 lb/day, 18.92 lb/hr	Method 7	Every permit term	
G.11, G.30, G.31, G.44, G.50, G.54, G.55, G.57 & G.58	PM/PM_{10} from SRU/ATS main stack	34.00 ton/yr, 186.3 lb/day, 7.76 lb/hr	Method 201A/Method 202	Every permit term	
			CAM	Continuous	
G.12, G.32, G.44, G.54, G.55, G.57 & G.58	CO from the SRU/ATS main stack	1.76 ton/yr, 0.40 lb/hr	Method 10	As required by the Department and Section III.A.1	
G.13, G.33, G.49, G.57 & G.58	NH_3 from SRU/ATS main stack	58.5 ton/yr, 320.5 lb/day, 13.36 lb/hr	Material Balance	Semiannually	
G.14, G.34, G.44, G.54, G.55, G.57 & G.58	Opacity of SRU/ATS main stack and SRU flare	20%	Method 9	As required by the Department and Section III.A.1	

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
G.15, G.35, G.49, G.57 & G.58	SO_2 from SRU flare	0.300 ton/day, 25.00 lb/hr	Material balance		Semiannually
G.16, G.36, G.49, G.53, G.57 & G.58	Jupiter Flare PM and CO	Negligible	Log	Semiannually	
G.17, G.37, G.41, G.43, G.44, G.54, G.55, G.57 & G.58	H_2S content of the flare fuel gas (and pilot gas)	0.10 grain/dscf on a 3-hour basis	Method 11	As required by the Department and Section III.A.1	
G.18, G.38, G.49, G.53, G.57 & G.58	Total SO_2 from SRU/ATS main stack plus the SRU flare	109.5 ton/yr (rolling 12-month average)	Log	Quarterly	
G.19, G.39, G.51, G.57 & G.58	Sour Water Stripper Diversion	Report Diversion	Ongoing	Semiannually	
G.20, G.40, G.52, G.57 & G.58	Vent off-gas from ASD to B304/B102	Must vent except for malfunctions	Ongoing	Semiannually	

Conditions

G.1. ConocoPhillips shall comply with all applicable requirements of 40 CFR 60.100 through 60.108, Subpart J, as they apply to the Jupiter SRU flare and the Claus units at the Jupiter sulfur recovery facility and any other applicable equipment (ARM 17.8.749 and ARM 17.8.1211).

G.2. ConocoPhillips shall meet the 40 CFR 60, Subpart A & J requirements by operating the Jupiter 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) (Consent Decree, ARM 17.8.749, ARM 17.8.340, and 40 CFR 60, Subpart J).

G.3. ConocoPhillips shall comply with all applicable requirements of 40 CFR 63, Subpart UUU-National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, including the requirement to prepare an OMMP according to the requirements in 40 CFR 63.1574 and operate at all times according to the procedures in the plan (ARM 17.8.342 and 40 CFR 63, Subpart UUU).

G.4. Jupiter SRU flare must be equipped and operated with a steam injection system. Flare tip height is to be based at a minimum of 213 feet from grade, plus or minus 3 feet (ARM 17.8.749 and ARM 17.8.1211).

G.5. ConocoPhillips shall not allow SO2 emissions from any flare, unless the emissions are a minor flaring event, or are the result of start-up, shutdown, or a malfunction as defined in ARM 17.8.110. A minor flaring event means a flaring event that emits less than or equal to 150 pounds of SO2 per 3-hour period (Board of Environmental Review Order signed on June 12, 1998. This requirement is “State Only”).

G.6. Except for minor flaring events, ConocoPhillips shall minimize SO2 emissions from flaring. In addition, when flaring of sulfur bearing gases occurs due to a malfunction, ConocoPhillips shall take immediate action to correct the malfunction (Board of Environmental Review Order signed on June 12, 1998. This requirement is “State Only”).

G.7. Any flow rate metering from upset or malfunctioning process units that are directed to either the refinery flare or the Jupiter SRU flare shall use approved standards, methods, accounting procedures, and engineering data (ARM 17.8.749 and ARM 17.8.1211).

G.8. The Jupiter SRU Incinerator (F-304) shall be equipped with low NOx burners (ARM 17.8.749 and ARM 17.8.1211).

G.9. SO2 emissions from the Jupiter SRU/ATS main stack shall be limited to 0.30 ton/day, 25.00 lb/hr (167 ppm, rolling 12-hour average corrected to 0% O2 on a dry basis) (ARM 17.8.749 and ARM 17.8.1211).

G.10. NOx emissions from the Jupiter SRU/ATS main stack shall be limited to 82.85 ton/yr, 454.0 lb/day, 18.92 lb/hr (ARM 17.8.749 and ARM 17.8.1211).

G.11. PM10 emissions from the Jupiter SRU/ATS main stack shall be limited to 34.00 ton/yr, 186.3 lb/day, 7.76 lb/hr (ARM 17.8.749 and ARM 17.8.1211).

G.12. CO emissions from the Jupiter SRU/ATS main stack shall be limited to 1.76 ton/yr, 0.40 lb/hr (ARM 17.8.749 and ARM 17.8.1211).

G.13. NH3 emissions from the Jupiter SRU/ATS main stack shall be limited to 58.5 ton/yr, 320.5 lb/day, 13.36 lb/hr (ARM 17.8.749 and ARM 17.8.1211).

G.14. ConocoPhillips shall not cause or authorize emissions to be discharged into the outdoor atmosphere from the SRU/ATS main stack or the Jupiter SRU flare that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.749 and ARM 17.8.1211).

G.15. SO2 emissions from the Jupiter SRU flare shall be limited to 0.30 ton/day, 25.00 lb/hr (ARM 17.8.749 and ARM 17.8.1211).

G.16. PM and CO emissions from the Jupiter SRU Flare shall be kept to their negligible levels (ARM 17.8.749 and ARM 17.8.1211).

G.17. H2S content of the flare fuel gas (and pilot gas) burned shall not exceed 0.10 grain/dscf on a 3-hour basis, 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, ARM 17.8.749 and ARM 17.8.1211).

G.18. Total SO2 emissions from the SRU/ATS main stack, plus the Jupiter SRU flare, shall not exceed 109.5 ton/yr (rolling 12-month average) (ARM 17.8.749 and ARM 17.8.1211).

G.19. 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 (ARM 17.8.749 and ARM 17.8.1211).

G.20. Jupiter shall vent off-gas from the Ammonium Sulfide Unit (ASD) unit operation to the B304/B102 sulfur boiler except during malfunction or maintenance conditions, when the off-gases would be vented to the Jupiter SRU flare (ARM 17.8.749).

Compliance Demonstration

G.21. ConocoPhillips shall comply with the test methods and monitoring requirements of 40 CFR 60.105, 60.106, and 60.108 to monitor compliance with the standards contained in 40 CFR 60.102, 60.103, and 60.104 (ARM 17.8.340 and 40 CFR 60, Subpart J).

G.22. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which reference 40 CFR 63, Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, including maintaining records to document conformance with procedures in ConocoPhillip's required OMMP (ARM 17.8.342; and 40 CFR 63, Subpart UUU).

G.23. ConocoPhillips shall log any failure in steam injection and any change in flare height for the Jupiter SRU flare, including the date, duration, circumstance, and operators initials (ARM 17.8.1213).

G.24. For purposes of determining whether a flaring event greater than 150 pounds of SO2 per 3-hour period has occurred, ConocoPhillips shall maintain records of all activities, other than de minimis activities, that result in SO2 emissions from the flare (Board of Environmental Review Order signed on June 12, 1998. This requirement is "State Only").

G.25. ConocoPhillips shall provide quarterly emission reports for the flare SO2 emissions based on H2S concentration information and flow information. The quarterly emission reports shall be submitted within 30 days of the end of each calendar quarter. The quarterly report shall consist of 24-hour calendar day totals per calendar month and shall include the following: (ARM 17.8.749 and ARM 17.8.1211):

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

b. Monitoring downtime that occurred during the reporting period;

c. A summary of excess emissions for each pollutant and averaging period; and

d. Emission estimates for SO2, other than de minimis activities, from material balance, engineering calculation data, and any emission testing.

G.26. ConocoPhillips shall inspect annually the low NOx burners on the incinerator and log any maintenance or inspections, including the date, circumstance, and operators initials (ARM 17.8.1213).

G.27. ConocoPhillips shall equip and operate the Jupiter SRU/ATS main stack with a SO2 CEMS, an O2 CEMS and a volumetric flow rate continuous emission rate monitor (ARM 17.8.749 and ARM 17.8.1211).

G.28. ConocoPhillips shall use CEMS data to monitor compliance with the SO2 limitations of Section III.G.9. ConocoPhillips shall also perform annual RATAs using Method 6/6C or other Department-approved method (ARM 17.8.1213).

G.29. ConocoPhillips shall perform a Method 7 source test or other Department approved method on an every-permit-term basis to monitor compliance with NOx limitations contained in Section III.G.10 (ARM 17.8.1213).

G.30. ConocoPhillips shall use pressure drop across the particulate filters to satisfy the compliance assurance monitoring (CAM) requirements of ARM 17.8 Subchapter 15 for the Jupiter SRU/ATS stack. Operation within the designated indicator ranges is deemed reasonable assurance of on-going compliance with the PM10 limitations in Sections III.G.11 (see the CAM Plan in Appendix F of this permit) (ARM 17.8.1212).

G.31. In addition to following the CAM Plan, ConocoPhillips shall perform a Method 5 and Method 201A/Method 202 source test or other Department approved method on an every-permit-term basis to monitor compliance with the PM10 limitations contained in Section III.G.11. The pressure drop indicator range or failure criteria will be updated for the CAM Plan, as necessary, based on data from the source test (ARM 17.8.105, ARM 17.8.106, and ARM 17.8.1213 and ARM 17.8.1504).

G.32. As required by the Department and Section III.A.1, ConocoPhillips shall perform a Method 10 source test or other Department approved method to monitor compliance with the CO limitations contained in Section III.G.12 (ARM 17.8.1213).

G.33. ConocoPhillips shall monitor compliance with Section III.G.13 by performing material balance calculations for ammonia (ARM 17.8.1213).

G.34. As required by the Department and Section III.A.1, ConocoPhillips shall perform a Method 9 source test to monitor compliance with the limitations contained in Section III.G.14 (ARM 17.8.1213).

G.35. As required by the Department and Section III.A.1, ConocoPhillips shall perform a Method 11 source test, material balance, or other Department approved method to monitor compliance for the SO2 limit at the Jupiter SRU flare contained in Section III.G.15 (ARM 17.8.1213).

G.36. ConocoPhillips shall inspect the Jupiter SRU flare annually, and log any maintenance or inspections including the date, duration, circumstance, and operators initials to confirm that the flare is operating properly, in order to comply with Section III.G.16 (ARM 17.8.1213).

G.37. As required by the Department and Section III.A.1, ConocoPhillips shall perform a Method 11 or other Department approved method to monitor compliance with the H2S limitation contained in Section III.G.17 (ARM 17.8.1213).

G.38. ConocoPhillips shall maintain a log, under ConocoPhillips's control, containing total SO2 emissions from the Jupiter SRU/ATS main stack plus the SRU flare for the year using a rolling 12-month average, to monitor compliance with the limitations in Section III.G.18 (ARM 17.8.1213).

G.39. ConocoPhillips shall maintain records any time in which the sour water stripper stream from the refinery is diverted away from the sulfur recovery facility (ARM 17.8.749 and ARM 17.8.1211).

G.40. ConocoPhillips shall maintain records to confirm that the off-gas from the ASD unit operation is vented as permitted (ARM 17.8.749 and ARM 17.8.1211).

G.41. Compliance with the emission limitations in Section III.G.9 shall be monitored by utilizing valid data taken from CEMS and other Department-approved sampling methods.

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, 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. SIP CEMS (SO_2) 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).

G.42. In order to accurately monitor the SO_2 emission rates in pounds per hour for the SRU/ATS Main Stack, ConocoPhillips shall perform annual source testing using EPA-approved methods (40 CFR Part 60, Appendix A, Methods 1-4 and 6/6C as appropriate for the Stipulation (STIP) and Exhibit A) or an equivalent method approved by the Department and EPA, and in accordance Section III.A.2 of this permit (ARM 17.8.106).

The annual RATAs required by Section 6(C) and (D) of the STIP may be substituted for the annual source tests, provided that the flow rate RATA and the concentration RATA are performed simultaneously and additional calculations are made to determine and report the data in pounds per hour of SO_2 ((ARM 17.8.749 and ARM 17.8.1211) and Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

G.43. ConocoPhillips shall provide quarterly emission reports from said emission rate monitors. Emission reporting for SO_2 from all point source locations shall consist of 24-hour calendar day totals per calendar month. The quarterly report shall be submitted within 30 days of the end of the calendar quarter and include the following: (ARM 17.8.749 and ARM 17.8.1211):

a. Source or unit operating times during the reporting period;

b. Monitoring downtime that occurred during the reporting period;

c. A summary of excess emissions for each pollutant and averaging period identified under each emission unit; and

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

Recordkeeping

G.44. ConocoPhillips shall perform all source testing recordkeeping in accordance with the appropriate test method and Section III.A.2 (ARM 17.8.106).

G.45. ConocoPhillips shall maintain recordkeeping in accordance with 40 CFR 60.107 (ARM 17.8.340 and 40 CFR 60, Subpart J).

G.46. ConocoPhillips shall keep all records as required by 40 CFR 63, Subpart UUU (ARM 17.8.342 and 40 CFR 63, Subpart UUU).

G.47. ConocoPhillips shall maintain a record of all flaring events other than flaring caused by de minimis activities. Each entry shall include the date; time; duration; an engineering estimate of the 3-hour emissions; the measured flow rate to the flare, if available; a description of the source and estimated equivalent sulfur content of the gases directed to the flare; a reason for the flaring event; a description of the immediate actions taken to correct the situation; and the operator's initials (Board of Environmental Review Order signed on June 12, 1998. This requirement is "State Only").

G.48. ConocoPhillips shall maintain, under ConocoPhillips's control, a log of the monthly inspection and maintenance performed on the flow rate-metering device used on upset or malfunctioning process units that are directed to either the refinery flare or the SRU flare (ARM 17.8.1212).

G.49. ConocoPhillips shall maintain, under ConocoPhillips's control, all records required for compliance demonstration, shall make all records available to Department personnel during inspections, and shall submit the records to the Department upon request (ARM 17.8.1212).

G.50. ConocoPhillips shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to ARM 17.8.1512 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under ARM 17.8 Subchapter 15 (ARM 17.8.1212 and ARM 17.8.1513).

G.51. 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 (H2S and NH3), 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 (ARM 17.8.749 and ARM 17.8.1211).

G.52. ConocoPhillips shall report to the Department any time in which the off-gas from the ASD unit is not vented to the B304/B102 boiler, including when the off-gas is vented to the Jupiter SRU flare (ARM 17.8.749 and ARM 17.8.1211).

G.53. ConocoPhillips shall maintain logs as required by Section III.G.23, III.G.26, III.G.36, and III.G.38 (ARM 17.8.1212).

Reporting

G.54. All source test reports shall be submitted to the Department in accordance Section III.A.2 (ARM 17.8.106).

G.55. ConocoPhillips shall notify the Department in writing of each source test or RATA a minimum of 25 working days prior to the actual testing, unless otherwise specified by the Department (Billings/Laurel SO_2 Emission Control Plan, approved into the SIP by EPA on May 2, 2002).

G.56. For flaring events in excess of 150 lb/3-hr period, ConocoPhillips shall comply with the reporting requirements identified in Section (3)(A)(5) of the Exhibit A-1 of the Stipulation (Board of Environmental Review Order Signed on June 12, 1998. This requirement is "State Only").

G.57. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1212).

G.58. The semiannual reporting shall provide (ARM 17.8.1212):

a. A summary of the results of any source tests performed during the period;

b. Reports of any required monitoring performed during the reporting period, with all instances of deviations from any permit requirements and corrective actions identified;

c. Certification that the quarterly emission reports were submitted as required by Section III.G.43; and

d. Certification that compliance with 40 CFR 60, Subpart J was maintained;

e. Certification that compliance with 40 CFR 63, Subpart UUU was maintained.

H. EU008 – Storage Tanks (non-Wastewater)

Refinery MACT 1 Group 1:
- Crude Oil Storage Tanks #1 and #2;
- Gasoline, Naphtha, and Other Storage Tanks: #3, #5, #7, #9, #12, #16, #21, #41, #42, #45, #46, #49, #52, #55, #72, #75, #80, #86, #87, #102, #110, #851, #2909

Refinery MACT 1 Group 2:
- Asphalt and PMA Storage Tanks #4, #62, #100, #101 & #3201
- Jet A, Distillate, and Diesel Storage Tanks #8, #10, #14, #20, #33, #47, #48, #53, #54, #57, #74,
- Residual and Fuel Oil Storage Tanks #6, #17,# 39, #40, #69, #70, #81, #104, #107
- Other Storage Tanks #11, #13, #18, #32, #59, #60, #82, #88, #91, #92, #116, #801

Organic Liquid Distribution (OLD) MACT:
- Proto Gas Tanks #2901 - #2907
- Dye & Other Tanks #78, #79 & #109

Other:
- Propane Tanks
- Tank #36 (out of service)

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirement
H.1, H.8, H.15, H.21 & H.22	Tank 49	Internal floating roof with double rim seal	Inspection	Annually	Semiannually
H.2, H.9, H.16, H.21 & H.22	Tanks 91, 92	40 CFR 60, Subpart K	40 CFR 60.113	As specified	Semiannually
H.3, H.10, H.16, H.21 & H.22	Tanks 100, 101, 102, 104	40 CFR 60, Subpart Ka	40 CFR 60.113a and/or 40 CFR 60.114a	As specified	Semiannually
H.4, H.11, H.16, H.20 - H.22	Tanks 36, 72, 107, 110, 851, 2909, 3201	40 CFR 60, Subpart Kb	40 CFR 60.113b and/or 40 CFR 60.114b	As specified	40 CFR 60.115b
H.5, H.12, H.17, H.21 & H.22	Tank 3201	40 CFR 60, Subpart UU	40 CFR 60.474	As specified	Semiannually
H.6, H.13, H.18, H.21 & H.22	Group 1 Storage Vessels	40 CFR 63.646, Subpart CC	40 CFR 63.646, Subpart CC	40 CFR 63.646, Subpart CC	40 CFR63.654, Subpart CC
H.7, H.14, H.19, H.21 & H.22	OLD Storage Vessels	40 CFR 63, Subpart EEEE	40 CFR 63, Subpart EEEE	40 CFR 63, Subpart EEEE	40 CFR 63, Subpart EEEE

Conditions

H.1. 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 and ARM 17.8.1211).

H.2. All volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after June 11, 1973, and prior to May 19, 1978, shall comply with requirements of 40 CFR 60, Subpart K. These requirements shall be as specified in 40 CFR 60.110 through 60.113. The affected tanks include, but are not limited to, tanks 91* and 92* (ARM 17.8.340 and 40 CFR 60, Subpart K).

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

H.3. 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 shall comply with requirements of 40 CFR 60, Subpart Ka. 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 (ARM 17.8.340 and 40 CFR 60, Subpart Ka):

Tank Number
#100*
#101*
#102
#104*
** Currently exempt from all emission control provisions due to vapor pressure of material stored.*

H.4. All volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984 shall comply with requirements of 40 CFR 60, Subpart Kb. These requirements shall be as specified in 40 CFR 60.110b through 60.115b. The affected tanks include, but are not limited to, the following (ARM 17.8.340 and 40 CFR 60, Subpart Kb):

Tank Number
#36
#72
#107*
#110*
#851
#2909
#T-3201*
** Currently exempt from all emission control provisions due to vapor pressure of material stored.*

H.5. The asphalt storage tank T-3201 and any other applicable storage tanks which commenced construction or modification after May 26, 1981, shall comply with all applicable requirements of 40 CFR 60, Subpart UU. Asphalt storage tank T-3201 shall comply with the standards of 40 CFR 60.472(c), including that 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 (ARM 17.8.340 and 40 CFR 60, Subpart UU).

H.6. All Group 1 Storage Vessels shall comply with all applicable requirements of 40 CFR 63, Subpart CC (ARM 17.8.342 and 40 CFR 63, Subpart CC).

H.7. All applicable (non-gasoline) Storage Vessels, including but not limited to Proto Gas and dye storage tanks, shall comply with all applicable requirements of 40 CFR 63, Subpart EEEE (ARM 17.8.342 and 40 CFR 63, Subpart EEEE).

Compliance Demonstration

H.8. ConocoPhillips shall perform annual inspections on Tank #49 to determine integrity of the roof, seal systems associated with the floating roof, and vents (ARM 17.8.1213).

H.9. ConocoPhillips shall monitor compliance with Section III.H.2 by complying with 40 CFR 60.113 (ARM 17.8.340 and 40 CFR 60, Subpart K).

H.10. ConocoPhillips shall monitor compliance with Section III.H.3 by complying with 40 CFR 60.113a and/or 40 CFR 60.114a (ARM 17.8.340 and 40 CFR 60, Subpart Ka).

H.11. ConocoPhillips shall monitor compliance with Section III.H.4 by complying with 40 CFR 60.113b and/or 40 CFR 60.114b (ARM 17.8.340 and 40 CFR 60, Subpart Kb).

H.12. ConocoPhillips shall monitor compliance with Section III.H.5 by complying with 40 CFR 60. 474 (ARM 17.8.340 and 40 CFR 60, Subpart UU).

H.13. ConocoPhillips shall monitor compliance with storage vessel provisions of 40 CFR 63.646 (ARM 17.8.342 and 40 CFR 63, Subpart CC).

H.14. ConocoPhillips shall monitor compliance with storage vessel provisions of 40 CFR 63, Subpart EEEE (ARM 17.8.342 and 40 CFR 63, Subpart EEEE).

Recordkeeping

H.15. ConocoPhillips shall maintain, under ConocoPhillips's control, a log of all inspections performed on Tank #49 as specified in Section III.H.8. This log shall contain the date, time, inspector's initials and the results of the inspection. If corrective action or repairs are made, a summary should be included in the log (ARM 17.8.1212).

H.16. ConocoPhillips shall maintain a log, under ConocoPhillips's control, for the monitoring required by 40 CFR 60.113, 40 CFR 60.115a, 40 CFR 60.115b, and 40 CFR 60.116b (ARM 17.8.340 and 40 CFR 60; Subpart K, Ka, and Kb).

H.17. ConocoPhillips shall maintain a log, under ConocoPhillips's control, for the monitoring required by 40 CFR 60.473 (ARM 17.8.340 and 40 CFR 60, Subpart UU).

H.18. ConocoPhillips shall comply with recordkeeping requirements of 40 CFR 63.646 and 63.654 (ARM 17.8.342 and 40 CFR 63, Subpart CC).

H.19. ConocoPhillips shall comply with recordkeeping requirements of 40 CFR 63.2390 (ARM 17.8.342 and 40 CFR 63, Subpart EEEE).

Reporting

H.20. ConocoPhillips shall submit reports in accordance with 40 CFR 60.115b (ARM 17.8.340 and 40 CFR 60, Subpart Kb).

H.21. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1212).

H.22. The semiannual reporting shall provide (ARM 17.8.1212):

a. A summary of the results of any source tests performed during the period;

b. Reports of any required monitoring performed during the reporting period, with all instances of deviations from any permit requirements and corrective actions identified;

c. Certification that compliance with 40 CFR 60, Subpart UU was maintained;

d. All required information for compliance monitoring for 40 CFR 63, Subpart CC. Nothing in this subparagraph requires the permittee to submit its MACT compliance report earlier than is required by the MACT regulations found in 40 CFR Subpart CC; and

e. All required information for compliance monitoring for 40 CFR 63, Subpart EEEE. Nothing in this subparagraph requires the permittee to submit its MACT compliance report earlier than is required by the MACT regulations found in 40 CFR Subpart EEEE.

I. EU0010 – Wastewater Treatment & Wastewater Storage Tanks

Wastewater Tanks:
- #15 – sour water
- #34, #35 & #164 – Slop Oil
- #4523 - WW Surge

Wastewater Separators:
- #163 – primary separator
- #169 & #170 – secondary separators (Corrugated Plate Interceptor (CPI) Separators)
- #4510 & #4511 – Desalter Break
- #4512 & #4513 – Coker Break

Oily Water Sewer Drain Systems:
- Coker unit,
- gas oil hydrotreater,
- No.1 Hydrogen Unit (20.0 MMscfd),
- No.2 Hydrogen Unit and No. 5 HDS Unit,
- C-23 compressor station,
- Alkylation Unit Butane Defluorinator Project,
- Alkylation Unit Depropanizer Project,
- #3 Sour Water Stripper (SWS),
- South Tank Farm, and
- Associated wastewater tanks.

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
I.1, I.7, I.13, I.19, I.21 & I.22	Tanks 35	40 CFR 60, Subpart Kb	40 CFR 60.113b and/or 40 CFR 60.114b	As specified	Semiannually
I.2, I.8, I.14, I.20 – I.22	Wastewater Treatment	40 CFR 60, Subpart QQQ	40 CFR 60, Subpart QQQ	40 CFR 60, Subpart QQQ	
I.3, I.9, I.15, I.21 & I.22	Wastewater Treatment	40 CFR 61, Subpart FF	40 CFR 61, Subpart FF	40 CFR 61, Subpart FF	
I.4, I.10, I.16, I.21 & I.22	Refinery MACT 1 Group 1 Storage Vessels	40 CFR 63 Subpart CC	40 CFR 63.646	40 CFR 63.646	
I.5, I.11, I.17, I.21 & I.22	Tanks 4510, 4511, 4512, and 4513	Internal floating roof with double rim seals or liquid mounted seal system.	Inspection	Annually	
I.6, I.12, I.18, I.21 & I.22	CPI Separator Tanks #169 & #170	Carbon Canisters designed and operated to reduce VOC emissions by 95%	Log	On-going	

Conditions

I.1. All volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984 shall comply with requirements of 40 CFR 60, Subpart Kb. These requirements shall be as specified in 40 CFR 60.110b through 60.115b. The affected tanks include, but are not limited to, Tanks #35 (ARM 17.8.340 and 40 CFR 60, Subpart Kb).

I.2. ConocoPhillips shall comply with all applicable requirements of 40 CFR 60, Subpart QQQ. This subpart applies to, but is not limited to wastewater separators and oily water sewer drain systems

and any other applicable equipment constructed, modified, or reconstructed after May 4, 1987, for requirements not overridden by 40 CFR 63, Subpart CC (ARM 17.8.340 and 40 CFR 60, Subpart QQQ).

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 shall be an oil/water (CPI) separator with hydrocarbon collection and recovery equipment.

c. All equipment shall be operated and maintained as required under 40 CFR 60, Subpart QQQ.

I.3. ConocoPhillips shall comply with all applicable requirements of 40 CFR 61, Subpart FF. This subpart applies to, but is not limited to, all new or recommissioned wastewater sewer drains associated with the Alkylation Unit Depropanizer Project; the refinery's existing sewer system; #3 SWS Unit, the new individual drain system for the waste stream associated with the No. 2 H_2 Unit and the No. 5 HDS Unit, and tanks 34 and 35 (ARM 17.8.341 and 40 CFR 61, Subpart FF).

I.4. All Group 1 Storage Vessels shall comply with all applicable requirements of 40 CFR 63, Subpart CC, except for those tanks subject to requirements under 40 CFR 60, Subpart Kb (ARM 17.8.342 and 40 CFR 63, Subpart CC).

I.5. Storage tank #4510, #4511, #4512, and #4513 shall be equipped with an internal floating roof with a double rim seal system or liquid mounted seal system for VOC loss control (ARM 17.8.752 and ARM 17.8.1211).

I.6. ConocoPhillips shall operate and maintain two (2) CPI separator tanks with carbon canister total VOC controls to comply with 40 CFR 60, Subpart QQQ and 40 CFR 61, Subpart FF regulations. The CPI separators will be vented to two (2) carbon canisters in series, designed and operated to reduce VOC emissions by 95% or greater, with no detectable emissions from the closed vent system (ARM 17.8.340; 40 CFR 60, Subpart QQQ; ARM 17.8.341; and 40 CFR 61, Subpart FF).

Compliance Demonstration

I.7. ConocoPhillips shall monitor compliance with Section III.I.1 by complying with 40 CFR 60.113b and/or 40 CFR 60.114b (ARM 17.8.340 and 40 CFR 60, Subpart Kb).

I.8. ConocoPhillips shall meet the requirements of all applicable testing and procedures of ARM 17.8.340, which references 40 CFR 60, Subpart QQQ, Standards of Performance for Volatile Organic Compound Emissions from Petroleum Refinery Wastewater Systems (ARM 17.8.340 and 40 CFR 60, Subpart QQQ).

I.9. ConocoPhillips shall meet the requirements of all applicable testing and procedures of ARM 17.8.341, which references 40 CFR 61, Subpart FF. This includes, but is not limited to, monitoring the exhaust vent stream from the waste water 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 (ARM 17.8.340; 40 CFR 60, Subpart QQQ; ARM 17.8.341; and 40 CFR 61, Subpart FF).

I.10. ConocoPhillips shall monitor compliance with applicable wastewater provisions of 40 CFR 63.647 (ARM 17.8.342 and 40 CFR 63, Subpart CC).

I.11. ConocoPhillips shall perform annual inspections on Tank #4510, #4511, #4512, and #4513 to determine integrity of the roofs, seal systems associated with the floating roofs, and vents (ARM 17.8.1213).

I.12. ConocoPhillips shall log any instance that carbon canisters are not used on the CPI Separator Tanks and any instance in which they may be operating without reducing VOC emissions by 95% or greater. The log shall include the date, duration, circumstances of the deviation, and operators initials (ARM 17.8.1213).

Recordkeeping

I.13. ConocoPhillips shall maintain a log, under ConocoPhillips's control, for the monitoring required by 40 CFR 60.115b, and 40 CFR 60.116b (ARM 17.8.340 and 40 CFR 60, Subpart Kb).

I.14. ConocoPhillips shall conduct all applicable recordkeeping requirements in accordance with 40 CFR 60, Subpart QQQ, for requirements not overridden by 40 CFR 63, Subpart CC (ARM 17.8.340 and 40 CFR 60, Subpart QQQ).

I.15. ConocoPhillips shall conduct all applicable recordkeeping requirements in accordance with 40 CFR 61, Subpart FF (ARM 17.8.341 and 40 CFR 60, Subpart FF).

I.16. ConocoPhillips shall comply with recordkeeping requirements of 40 CFR 63.646 and 63.654 (ARM 17.8.342 and 40 CFR 63, Subpart CC).

I.17. ConocoPhillips shall maintain, under ConocoPhillips's control, a log of all inspections performed on the tanks listed in Section III.I.12. This log shall contain the date, time, inspector's initials and the results of the inspection. If corrective action or repairs are made, a summary should be included in the log (ARM 17.8.1212).

I.18. ConocoPhillips shall maintain, under ConocoPhillips's control, a log as required by Section III.I.13 (ARM 17.8.1212).

Reporting

I.19. ConocoPhillips shall submit reports in accordance with 40 CFR 60.115b (ARM 17.8.340 and 40 CFR 60, Subpart Kb).

I.20. ConocoPhillips shall provide the Department copies of testing results, monitoring operations, recordkeeping, and report results, upon request of the Department or 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 (ARM 17.8.340 and 40 CFR 60, Subpart QQQ).

I.21. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1212).

I.22. The semiannual reporting shall provide (ARM 17.8.1212):

a. A summary of results of any source testing that was performed during the period;

b. Reports of any required monitoring performed during the reporting period, with all instances of deviations from any permit requirements and corrective actions identified;

c. A summary of reporting done to conform to requirements of 40 CFR 60, Subpart QQQ;

d. A summary of reporting done to conform to requirements of 40 CFR 61, Subpart FF; and

e. All required information for compliance monitoring for 40 CFR 63, Subpart CC. Nothing in this subparagraph requires the permittee to submit its MACT compliance report earlier than is required by the MACT regulations found in 40 CFR Subpart CC.

J. EU0011 – Miscellaneous Process Vents

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
J.1, J.3, J.5, J.7, J.8	Miscellaneous Process Vents	40 CFR 63, Subpart CC	40 CFR 63.644 &645	40 CFR 63.644 &645	40 CFR 63.654
J.2, J.4, J.6 – J.8	CO Emissions - No. 1 &No. 2 H2 Units PSA Off-gas Vents	Document number and estimated emissions	Log	Monthly	

Conditions

J.1. ConocoPhillips shall comply with all applicable requirements of 40 CFR 63.643 as they apply to the units required to comply with the Miscellaneous Process Vents (ARM 17.8.342 and 40 CFR 63, Subpart CC).

J.2. ConocoPhillips shall document, by month, the number of PSA off-gas venting occurrences and the estimated CO emissions from each venting occurrence, by the No.1 H_2 Unit PSA Off-gas Vent and the No.2 H_2 Unit PSA Off-gas Vent (ARM 17.8.749 and ARM 17.8.1211).

Compliance Demonstration

J.3. Compliance monitoring for miscellaneous process vents shall be performed in accordance with 40 CFR 63.654, 63.644, and/or 63.645, as appropriate (ARM 17.8.342 and 40 CFR 63, Subpart CC).

J.4. ConocoPhillips shall document, by month, the number of PSA off-gas venting occurrences and the estimated CO emissions from each venting occurrence by the by the No.1 H_2 Unit PSA Off-gas vent and the No.2 H_2 Unit PSA Off-gas vent. By the 30th day of each month, ConocoPhillips shall total the number of PSA off-gas venting occurrences and the estimated CO emissions from each venting occurrence by each 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).

Recordkeeping

J.5. Recordkeeping for miscellaneous process vents shall be performed in accordance with 40 CFR 63.654, 63.644, and/or 63.645, as appropriate (ARM 17.8.342 and 40 CFR 63, Subpart CC).

J.6. ConocoPhillips shall maintain, under ConocoPhillips's control, all logs required for monitoring compliance, shall make all logs available to Department personnel during inspections, and shall submit the logs to the Department upon request (ARM 17.8.1212).

Reporting

J.7. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1212).

J.8. The semiannual reporting shall provide (ARM 17.8.1212):

a. Reports of any required monitoring performed during the reporting period, with all instances of deviations from any permit requirements and corrective actions identified; and

b. Certification that compliance with 40 CFR 63, Subpart CC was maintained.

K. EU012 –Catalytic Reforming Units 1 & 2

Catalytic Reforming Units #1 & #2

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
K.1, K.3, K.6, K.7, K.9, K.10	Catalytic Reforming Units	40 CFR 63, Subpart UUU	40 CFR 63, Subpart UUU	40 CFR 63, Subpart UUU	Semiannually
K.2, K.4, K.5, K.6, K.8 – K.10	PM, Industrial Processes	$E= 4.10 * P^{0.67}$ or $E= 55 * P^{0.11} - 40$	Method 5	As required by the Department and Section III.A.1	

Conditions

K.1. ConocoPhillips shall comply with all applicable requirements of 40 CFR 63, Subpart UUU-National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, including the requirement to prepare an Operation, Maintenance, and Monitoring Plan (OMMP) according to the requirements in 40 CFR 63.1574 and operate at all times according to the procedures in the plan. Catalytic Reforming Unit #2 is subject to the Subpart UUU requirements. Catalytic Reforming Unit #1 is not subject as long as the reformer is dormant or the catalyst is regenerated off-site (ARM 17.8.342; and 40 CFR 63, Subpart UUU).

K.2. ConocoPhillips shall not cause or authorize particulate matter to be discharged from any operation, process, or activity into the outdoor atmosphere in excess of the maximum hourly allowable emissions of particulate matter, calculated using the following equations:

For process weight rates up to 30 tons per hour: $E = 4.10 * P^{0.67}$

For process weight rates in excess of 30 tons per hour: $E = 55.0 * P^{0.11} – 40$

Where E is the rate of emissions in pounds per hour and P is the process weight rate in tons per hour (ARM 17.8.310).

Compliance Demonstration

K.3. ConocoPhillips shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which reference 40 CFR 63, Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, including maintaining records to document conformance with procedures in ConocoPhillip's required OMMP (ARM 17.8.342; and 40 CFR 63, Subpart UUU).

K.4. In accordance with Section III.A.1 and as required by the Department, ConocoPhillips shall perform Method 5 testing or other Department approved testing on the Catalytic Reforming Units 1 & 2, to monitor compliance with PM limitations in Section III.K.2 (ARM 17.8.1213).

Recordkeeping

K.5. All source test recordkeeping shall be performed in accordance with the test method being used and Section III.A.2 (ARM 17.8.106).

K.6. Recordkeeping compiled for purposes of monitoring compliance with emission limits shall be retained by ConocoPhillips for a minimum of 5-years (ARM 17.8.1212).

K.7. ConocoPhillips shall keep all records as required by 40 CFR 63, Subpart UUU (ARM 17.8.342 and 40 CFR 63, Subpart UUU).

Reporting

K.8. All source test reports shall be submitted to the Department in accordance with Section III.A.2 (ARM 17.8.106).

K.9. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1212).

K.10. The semiannual reporting shall provide (ARM 17.8.1212):

a. A summary of the results of any source tests performed during the period; and

b. Certification that compliance with 40 CFR 63, Subpart UUU was maintained.

SECTION IV. NON-APPLICABLE REQUIREMENTS

Air Quality Administrative Rules of Montana (ARM) and Federal Regulations identified as not applicable to the facility or to a specific emissions unit at the time of the permit issuance are listed below (ARM 17.8.1214). The following list does not preclude the need to comply with any new requirements that may become applicable during the permit term.

A. Facility-Wide

The following table contains non-applicable requirements that are administrated by the Air and Waste Management Bureau of the Department of Environmental Quality.

Rule Citation	Reason
ARM 17.8.320, ARM 17.8.321, ARM 17.8.323, ARM 17.8 331, ARM 17.8.332, ARM 17.8.333, and ARM 17.8.334.	These rules are not applicable because the facility is not listed in the source category cited or does not have the specific emissions unit cited in the rules.
40 CFR 60, Subparts B, C, Ca, Cb 40 CFR 60, Subparts D, Da 40 CFR 60, Subparts E-I 40 CFR 60, Subparts L-Z 40 CFR 60, Subparts AA-EE 40 CFR 60, Subparts GG-HH 40 CFR 60, Subparts KK-NN 40 CFR 60, Subparts PP-TT 40 CFR 60, Subparts WW 40 CFR 60, Subparts AAA- DDD 40 CFR 60, Subparts FFF 40 CFR 60, Subparts HHH-LLL 40 CFR 60, Subparts NNN-PPP 40 CFR 60, Subparts RRR-WWW	These requirements are not applicable because the facility is not an affected source as defined in these regulations.
40 CFR 61, Subparts B-F 40 CFR 61, Subparts H-L 40 CFR 61, Subparts N 40 CFR 61, Subparts O-R 40 CFR 61, Subpart T 40 CFR 61, Subparts V-W 40 CFR 61, Subpart Y 40 CFR 61, Subpart BB	These requirements are not applicable because the facility is not an affected source as defined in these regulations.
40 CFR 63, Subpart B 40 CFR 63, Subparts F-I 40 CFR 63, Subparts L-O 40 CFR 63, Subparts Q-R 40 CFR 63, Subpart T-Y 40 CFR 63, Subparts DD-EE 40 CFR 63, Subpart GG	These requirements are not applicable because the facility is not an affected source as defined in these regulations.
40 CFR 82, Subparts A-E 40 CFR 82, Subparts G-H	These requirements are not applicable because the facility is not an affected source as defined in these regulations.
40 CFR 72 through 40 CFR 78.	These requirements are not applicable because the facility is not an affected source as defined by the acid rain regulations.

B. Emission Units

The permit application identified applicable requirements; non-applicable requirements for individual or specific emission units were not listed. The Department has listed all non-applicable requirements in Section IV.A. These requirements relate to each specific unit as well as facility wide.

SECTION V. GENERAL PERMIT CONDITIONS

A. Compliance Requirements

ARM 17.8, Subchapter 12, Operating Permit Program §1210(2)(a)-(c)&(e), §1206(6)(c)&(b)

1. The permittee must comply with all conditions of the permit. Any noncompliance with the terms or conditions of the permit constitutes a violation of the Montana Clean Air Act, and may result in enforcement action, permit modification, revocation and reissuance, or termination, or denial of a permit renewal application under ARM Title 17, Chapter 8, Subchapter 12.

2. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

3. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. If appropriate, this factor may be considered as a mitigating factor in assessing a penalty for noncompliance with an applicable requirement if the source demonstrates that both the health, safety or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations, and that such health, safety or environmental impacts were unforeseeable and could not have otherwise been avoided.

4. The permittee shall furnish to the Department, within a reasonable time set by the Department (not to be less than 15 days), any information that the Department may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Department copies of those records that are required to be kept pursuant to the terms of the permit. This subsection does not impair or otherwise limit the right of the permittee to assert the confidentiality of the information requested by the Department, as provided in 75-2-105, MCA.

5. Any schedule of compliance for applicable requirements with which the source is not in compliance with at the time of permit issuance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it was based.

6. For applicable requirements that will become effective during the permit term, the source shall meet such requirements on a timely basis unless a more detailed plan or schedule is required by the applicable requirement or the Department.

B. Certification Requirements

ARM 17.8, Subchapter 12, Operating Permit Program §1207 and §1213(7)(a)&(c)-(d)

1. Any application form, report, or compliance certification submitted pursuant to ARM Title 17, Chapter 8, Subchapter 12, shall contain certification by a responsible official of truth, accuracy and completeness. This certification and any other certification required under ARM Title 17, Chapter 8, Subchapter 12, shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

2. Compliance certifications shall be submitted by February 15th of each year, or more frequently if otherwise specified in an applicable requirement or elsewhere in the permit. Each certification must include the required information for the previous calendar year (i.e., January 1 – December 31).

3. Compliance certifications shall include the following:

   a. The identification of each term or condition of the permit that is the basis of the certification;

   b. The identification of the method(s) or other means used by the owner or operator for determining the status of compliance with each term and condition during the certification period, consistent with ARM 17.8.1212;

   c. The status of compliance with each term and condition for the period covered by the certification, *including whether compliance during the period was continuous or intermittent* (based on the method or means identified in ARM 17.8.1213(7)(c)(ii), as described above); and

   d. Such other facts as the Department may require to determine the compliance status of the source.

4. All compliance certifications must be submitted to the Environmental Protection Agency, as well as to the Department, at the addresses listed in the Notification Addresses Appendix of this permit.

C. Permit Shield
ARM 17.8, Subchapter 12, Operating Permit Program §1214(1)-(4)

1. The applicable requirements and non-federally enforceable requirements are included and specifically identified in this permit and the permit includes a precise summary of the requirements not applicable to the source. Compliance with the conditions of the permit shall be deemed compliance with any applicable requirements and any non-federally enforceable requirements as of the date of permit issuance.

2. The permit shield described in 1 above shall remain in effect during the appeal of any permit action (renewal, revision, reopening, or revocation and reissuance) to the Board of Environmental Review (Board), until such time as the Board renders its final decision.

3. Nothing in this permit alters or affects the following:

   a. The provisions of Sec. 7603 of the FCAA, including the authority of the administrator under that section;

   b. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

   c. The applicable requirements of the Acid Rain Program, consistent with Sec. 7651g(a) of the FCAA;

   d. The ability of the administrator to obtain information from a source pursuant to Sec. 7414 of the FCAA;

   e. The ability of the Department to obtain information from a source pursuant to the Montana Clean Air Act, Title 75, Chapter 2, MCA;

   f. The emergency powers of the Department under the Montana Clean Air Act, Title 75, Chapter 2, MCA; and

g. The ability of the Department to establish or revise requirements for the use of Reasonably Available Control Technology (RACT) as defined in ARM Title 17, Chapter 8. However, if the inclusion of a RACT into the permit pursuant to ARM Title 17, Chapter 8, Subchapter 12, is appealed to the Board, the permit shield, as it applies to the source's existing permit, shall remain in effect until such time as the Board has rendered its final decision.

4. Nothing in this permit alters or affects the ability of the Department to take enforcement action for a violation of an applicable requirement or permit term demonstrated pursuant to ARM 17.8.106, Source Testing Protocol.

5. Pursuant to ARM 17.8.132, for the purpose of submitting a compliance certification, nothing in these rules shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance. However, when compliance or noncompliance is demonstrated by a test or procedure provided by permit or other applicable requirements, the source shall then be presumed to be in compliance or noncompliance unless that presumption is overcome by other relevant credible evidence.

6. The permit shield will not extend to minor permit modifications or changes not requiring a permit revision (see Sections I & J).

7. The permit shield will extend to significant permit modifications and transfer or assignment of ownership (see Sections K & O).

D. Monitoring, Recordkeeping, and Reporting Requirements
ARM 17.8, Subchapter 12, operating Permit Program §1212(2)&(3)

1. Unless otherwise provided in this permit, the permittee shall maintain compliance monitoring records that include the following information:

   a. The date, place as defined in the permit, and time of sampling or measurement;

   b. The date(s) analyses were performed;

   c. The company or entity that performed the analyses;

   d. The analytical techniques or methods used;

   e. The results of such analyses; and

   f. The operating conditions at the time of sampling or measurement.

2. The permittee shall retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. All monitoring data, support information, and required reports and summaries may be maintained in computerized form at the plant site if the information is made available to Department personnel upon request, which may be for either hard copies or computerized format. Strip-charts must be maintained in their original form at the plant site and shall be made available to Department personnel upon request.

3. The permittee shall submit to the Department, at the addresses located in the Notification Addresses Appendix of this permit, reports of any required monitoring by February 15th and August 15th of each year, or more frequently if otherwise specified in an applicable requirement or elsewhere in the permit. The monitoring report submitted on February 15th of each year must include the required monitoring information for the period of July 1 through December 31 of the previous year. The monitoring report submitted on August 15th of each year must include the required monitoring information for the period of January 1 through June 30 of the current year. All instances of deviations from the permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official, consistent with ARM 17.8.1207.

E. Prompt Deviation Reporting
ARM 17.8, Subchapter 12, Operating Permit Program §1212(3)(c)

The permittee shall promptly report deviations from permit requirements, including those attributable to upset conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. To be considered prompt, deviations shall be reported as part of the routine reporting requirements under ARM 17.8.1212(3)(b) and, if applicable, in accordance with the malfunction reporting requirements under ARM 17.8.110, unless otherwise specified in an applicable requirement.

F. Emergency Provisions
ARM 17.8, Subchapter 12, Operating Permit Program §1201(13) and §1214(5), (6)&(8)

1. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation and causes the source to exceed a technology-based emission limitation under this permit due to the unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of reasonable preventive maintenance, careless or improper operation, or operator error.

2. An emergency constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the permittee demonstrates through properly signed, contemporaneous logs, or other relevant evidence, that:

   a. An emergency occurred and the permittee can identify the cause(s) of the emergency;

   b. The permitted facility was at the time being properly operated;

   c. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in the permit; and

   d. The permittee submitted notice of the emergency to the Department within 2 working days of the time when emission limitations were exceeded due to the emergency. This notice fulfills the requirements of ARM 17.8.1212(3)(c). This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

3. These emergency provisions are in addition to any emergency, malfunction or upset provision contained in any applicable requirement.

G. Inspection and Entry

ARM 17.8, Subchapter 12, Operating Permit Program §1213(3)&(4)

1. Upon presentation of credentials and other requirements as may be required by law, the permittee shall allow the Department, the administrator, or an authorized representative (including an authorized contractor acting as a representative of the Department or the administrator) to perform the following:

   a. Enter the premises where a source required to obtain a permit is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;

   b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

   c. Inspect at reasonable times any facilities, emission units, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

   d. As authorized by the Montana Clean Air Act and rules promulgated thereunder, sample or monitor, at reasonable times, any substances or parameters at any location for the purpose of assuring compliance with the permit or applicable requirements.

2. The permittee shall inform the inspector of all workplace safety rules or requirements at the time of inspection. This section shall not limit in any manner the Department's statutory right of entry and inspection as provided for in 75-2-403, MCA.

H. Fee Payment

ARM 17.8, Subchapter 12, Operating Permit Program §1210(2)(f) and ARM 17.8, Subchapter 5, Air Quality Permit Application, Operation, and Open Burning Fees §505(3)-(5) (STATE ONLY)

1. The permittee must pay application and operating fees, pursuant to ARM Title 17, Chapter 8, Subchapter 5.

2. Annually, the Department shall provide the permittee with written notice of the amount of the fee and the basis for the fee assessment. The air quality operation fee is due 30 days after receipt of the notice, unless the fee assessment is appealed pursuant to ARM 17.8.511. If any portion of the fee is not appealed, that portion of the fee that is not appealed is due 30 days after receipt of the notice. Any remaining fee, which may be due after the completion of an appeal, is due immediately upon issuance of the Board's decision or upon completion of any judicial review of the Board's decision.

3. If the permittee fails to pay the required fee (or any required portion of an appealed fee) within 90 days of the due date of the fee, the Department may impose an additional assessment of 15% of the fee (or any required portion of an appealed fee) or $100, whichever is greater, plus interest on the fee (or any required portion of an appealed fee), computed at the interest rate established under 15-31-510(3), MCA.

I. Minor Permit Modifications

ARM 17.8, Subchapter 12, Operating Permit Program §1226(3)&(11)

1. An application for a minor permit modification need only address in detail those portions of the permit application that require revision, updating, supplementation, or deletion, and may reference any required information that has been previously submitted.

2. The permit shield under ARM 17.8.1214 will not extend to any minor modifications processed pursuant to ARM 17.8.1226.

J. Changes Not Requiring Permit Revision
ARM 17.8, Subchapter 12, Operating Permit Program §1224(1)-(3), (5)&(6)

1. The permittee is authorized to make changes within the facility as described below, provided the following conditions are met.

   a. The proposed changes do not require the permittee to obtain an air quality preconstruction permit under ARM Title 17, Chapter 8, Subchapter 7;

   b. The proposed changes are not modifications under Title I of the FCAA, or as defined in ARM Title 17, Chapter 8, Subchapters 8, 9, or 10;

   c. The emissions resulting from the proposed changes do not exceed the emissions allowable under this permit, whether expressed as a rate of emissions or in total emissions;

   d. The proposed changes do not alter permit terms that are necessary to enforce applicable emission limitations on emission units covered by the permit; and

   e. The facility provides the administrator and the Department with written notification at least 7 days prior to making the proposed changes.

2. The permittee and the Department shall attach each notice provided pursuant to 1.e above to their respective copies of this permit.

3. Pursuant to the conditions above, the permittee is authorized to make Section 502(b)(10) changes, as defined in ARM 17.8.1201(30), without a permit revision. For each such change, the written notification required under 1.e above shall include a description of the change within the source, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change.

4. The permittee may make a change not specifically addressed or prohibited by the permit terms and conditions without requiring a permit revision, provided the following conditions are met.

   a. Each proposed change does not weaken the enforceability of any existing permit conditions;

   b. The Department has not objected to such change;

   c. Each proposed change meets all applicable requirements and does not violate any existing permit term or condition; and

   d. The permittee provides contemporaneous written notice to the Department and the administrator of each change that is above the level for insignificant emission units as defined in ARM 17.8.1201(22) and 17.8.1206(3), and the written notice describes each such change, including the date of the change, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change.

5. The permit shield authorized by ARM 17.8.1214 shall not apply to changes made pursuant to ARM 17.8.1224(3) and (5), but is applicable to terms and conditions that allow for increases and decreases in emissions pursuant to ARM 17.8.1224(4).

K. Significant Permit Modifications
ARM 17.8, Subchapter 12, Operating Permit Program §1227(1), (3)&(4)

1. The modification procedures set forth in 2 below must be used for any application requesting a significant modification of this permit. Significant modifications include the following:

   a. Any permit modification that does not qualify as either a minor modification or as an administrative permit amendment;

   b. Every significant change in existing permit monitoring terms or conditions;

   c. Every relaxation of permit reporting or recordkeeping terms or conditions that limit the Department's ability to determine compliance with any applicable rule, consistent with the requirements of the rule; or

   d. Any other change determined by the Department to be significant.

2. Significant modifications shall meet all requirements of ARM Title 17, Chapter 8, including those for applications, public participation, and review by affected states and the administrator, as they apply to permit issuance and renewal, except that an application for a significant permit modification need only address in detail those portions of the permit application that require revision, updating, supplementation or deletion.

3. The permit shield provided for in ARM 17.8.1214 shall extend to significant modifications.

L. Reopening for Cause
ARM 17.8, Subchapter 12, Operating Permit Program §1228(1)&(2)

1. This permit may be reopened and revised under the following circumstances:

   a. Additional applicable requirements under the FCAA become applicable to the facility when the permit has a remaining term of 3 or more years. Reopening and revision of the permit shall be completed not later than 18 months after promulgation of the applicable requirement. No reopening is required under ARM 17.8.1228(1)(a) if the effective date of the applicable requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms or conditions have been extended pursuant to ARM 17.8.1220(12) or 17.8.1221(2);

   b. Additional requirements (including excess emission requirements) become applicable to an affected source under the Acid Rain Program. Upon approval by the administrator, excess emission offset plans shall be deemed incorporated into the permit;

   c. The Department or the administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emission standards or other terms or conditions of the permit; or

   d. The administrator or the Department determines that the permit must be revised or revoked and reissued to ensure compliance with the applicable requirements.

M. Permit Expiration and Renewal
ARM 17.8, Subchapter 12, Operating Permit Program §1210(2)(g), §1220(11)&(12), and §1205(2)(d)

1. This permit is issued for a fixed term of 5 years.

2. Renewal of this permit is subject to the same procedural requirements that apply to permit issuance, including those for application, content, public participation, and affected state and administrator review.

3. Expiration of this permit terminates the permittee's right to operate unless a timely and administratively complete renewal application has been submitted consistent with ARM 17.8.1221 and 17.8.1205(2)(d). If a timely and administratively complete application has been submitted, all terms and conditions of the permit, including the application shield, remain in effect after the permit expires until the permit renewal has been issued or denied.

4. For renewal, the permittee shall submit a complete air quality operating permit application to the Department not later than 6 months prior to the expiration of this permit, unless otherwise specified. If necessary to ensure that the terms of the existing permit will not lapse before renewal, the Department may specify, in writing to the permittee, a longer time period for submission of the renewal application. Such written notification must be provided at least 1 year before the renewal application due date established in the existing permit.

N. Severability Clause
ARM 17.8, Subchapter 12, Operating Permit Program §1210(2)(i)&(l)

1. The administrative appeal or subsequent judicial review of the issuance by the Department of an initial permit under this subchapter shall not impair in any manner the underlying applicability of all applicable requirements, and such requirements continue to apply as if a final permit decision had not been reached by the Department.

2. If any provision of a permit is found to be invalid, all valid parts that are severable from the invalid part remain in effect. If a provision of a permit is invalid in one or more of its applications, the provision remains in effect in all valid applications that are severable from the invalid applications.

O. Transfer or Assignment of Ownership
ARM 17.8, Subchapter 12, Operating Permit Program §1225(2)&(4)

1. If an administrative permit amendment involves a change in ownership or operational control, the applicant must include in its request to the Department a written agreement containing a specific date for the transfer of permit responsibility, coverage and liability between the current and new permittee.

2. The permit shield provided for in ARM17.8.1214 shall not extend to administrative permit amendments.

P. Emissions Trading, Marketable Permits, Economic Incentives
ARM 17.8, Subchapter 12, Operating Permit Program §1226(2)

Notwithstanding ARM 17.8.1226(1) and (7), minor air quality operating permit modification procedures may be used for permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, to the extent that such minor permit modification procedures are explicitly provided for in the Montana State Implementation Plan or in applicable requirements promulgated by the administrator.

Q. No Property Rights Conveyed
ARM 17.8, Subchapter 12, Operating Permit Program §1210(2)(d)

This permit does not convey any property rights of any sort, or any exclusive privilege.

R. Testing Requirements
ARM 17.8, Subchapter 1, General Provisions §105

The permittee shall comply with ARM 17.8.105.

S. Source Testing Protocol
ARM 17.8, Subchapter 1, General Provisions §106

The permittee shall comply with ARM 17.8.106.

T. Malfunctions
ARM 17.8, Subchapter 1, General Provisions §110

The permittee shall comply with ARM 17.8.110.

U. Circumvention
ARM 17.8, Subchapter 1, General Provisions §111

The permittee shall comply with ARM 17.8.111.

V. Motor Vehicles
ARM 17.8, Subchapter 3, Emission Standards §325

The permittee shall comply with ARM 17.8.325.

W. Annual Emissions Inventory
ARM 17.8, Subchapter 5, Air Quality Permit Application, Operation and Open Burning Fees §505 (STATE ONLY)

The permittee shall supply the Department with annual production and other information for all emission units necessary to calculate actual or estimated actual amount of air pollutants emitted during each calendar year. Information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request, unless otherwise specified in this permit. Information shall be in the units required by the Department.

X. Open Burning
ARM 17.8, Subchapter 6, Open Burning §604, 605 and 606

The permittee shall comply with ARM 17.8.604, 605 and 606.

Y. Montana Air Quality Permits
ARM 17.8, Subchapter 7, Permit, Construction and Operation of Air Contaminant Sources §745 and 764 (ARM 17.8.745(1) and 764(1)(b) are STATE ENFORCEABLE ONLY until approval by the EPA as part of the SIP)

1. Except as specified, no person shall construct, install, alter or use any air contaminant source or stack associated with any source without first obtaining a permit from the Department or Board. A permit is not required for those sources or stacks as specified by ARM 17.8.744(1)(a)-(k).

2. The permittee shall comply with ARM 17.8.743, 744, 745, 748, and 764.

3. ARM 17.8.745(1) specifies de minimis changes as construction or changed conditions of operation at a facility holding an air quality preconstruction permit issued under Chapter 8 that

does not increase the facility's potential to emit by more than 15 tons per year of any pollutant, except (STATE ENFORCEABLE ONLY until approved by the EPA as part of the SIP):

a. Any construction or changed condition that would violate any condition in the facility's existing air quality preconstruction permit or any applicable rule contained in Chapter 8 is prohibited, except as provided in ARM 17.8.745(2);

b. Any construction or changed conditions of operation that would qualify as a major modification under Subchapters 8, 9 or 10 of Chapter 8;

c. Any construction or changed condition of operation that would affect the plume rise or dispersion characteristic of emissions that would cause or contribute to a violation of an ambient air quality standard or ambient air increment as defined in ARM 17.8.804;

d. Any construction or improvement project with a potential to emit more than 15 tons per year may not be artificially split into smaller projects to avoid air quality preconstruction permitting; or

e. Emission reductions obtained through offsetting within a facility are not included when determining the potential emission increase from construction or changed conditions of operation, unless such reductions are made federally enforceable.

4. Any facility making a de minimis change pursuant to ARM 17.8.745(1) shall notify the Department if the change would include a change in control equipment, stack height, stack diameter, 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, 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). (STATE ENFORCEABLE ONLY until approval by the EPA as part of the SIP).

Z. National Emission Standard for Asbestos
40 CFR, Part 61, Subpart M

The permittee shall not conduct any asbestos abatement activities except in accordance with 40 CFR 61, Subpart M (National Emission Standard for Hazardous Air Pollutants for Asbestos).

AA. Asbestos
ARM 17.74, Subchapter 3, General Provisions and Subchapter 4, Fees

The permittee shall comply with ARM 17.74.301, *et seq*., and ARM 17.74.401, *et seq*. (State only)

BB. Stratospheric Ozone Protection – Servicing of Motor Vehicle Air Conditioners
40 CFR, Part 82, Subpart B

If the permittee performs a service on motor vehicles and this service involves ozone-depleting substance/refrigerant in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR 82, Subpart B.

CC. Stratospheric Ozone Protection – Recycling and Emission Reductions

40 CFR, Part 82, Subpart F

The permittee shall comply with the standards for recycling and emission reductions in 40 CFR 82, Subpart F, except as provided for MVACs in Subpart B.

1. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.

2. Equipment used during the maintenance, service, repair or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.

3. Persons performing maintenance, service, repair or disposal of appliances must be certified by an approved technical certification program pursuant to §82.161.

4. Persons disposing of small appliances, MVACs and MVAC-like (as defined at §82.152) appliances must comply with recordkeeping requirements pursuant to §82.166.

5. Persons owning commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to §82.156.

6. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

DD. Emergency Episode Plan

The permittee shall comply with the requirements contained in Chapter 9.7 of the State of Montana Air Quality Control Implementation Plan.

Each major source emitting 100 tons per year located in a Priority I Air Quality Control Region, shall submit to the Department a legally enforceable Emergency Episode Action Plan (EEAP) that details how the source will curtail emissions during an air pollutant emergency episode. The industrial EEAP shall be in accordance with the Department's EEAP and shall be submitted according to a timetable developed by the Department, following Priority I reclassification.

EE. Definitions

Terms not otherwise defined in this permit or in the Definitions and Abbreviations Appendix of this permit, shall have the meaning assigned to them in the referenced regulations.

APPENDICES

APPENDIX A INSIGNIFICANT EMISSION UNITS

Disclaimer: The information in this appendix is not State or Federally enforceable, but is presented to assist ConocoPhillips, the permitting authority, inspectors, and the public.

Pursuant to ARM 17.8.1201(22)(a), an insignificant emission unit means any activity or emission unit located within a source that: (i) has a potential to emit less than 5 tons per year of any regulated pollutant; (ii) has a potential to emit less than 500 pounds per year of lead; (iii) has a potential to emit less than 500 pounds per year of hazardous air pollutants listed pursuant to Sec. 7412 (b) of the FCAA; and (iv) is not regulated by an applicable requirement, other than a generally applicable requirement that applies to all emission units subject to Subchapter 12.

List of Insignificant Activities:

ConocoPhillips provided an update to the June 12, 1996 application on May 3, 2000 in which all references to insignificant sources were either moved to significant units or deleted from the previous list.

APPENDIX B DEFINITIONS and ABBREVIATIONS

"Act" means the Clean Air Act, as amended, 42 U.S. 7401, *et seq*.

"Administrative permit amendment" means an air quality operating permit revision that:

(a) Corrects typographical errors;

(b) Identifies a change in the name, address or phone number of any person identified in the air quality operating permit, or identifies a similar minor administrative change at the source;

(c) Requires more frequent monitoring or reporting by ConocoPhillips;

(d) Requires changes in monitoring or reporting requirements that the Department deems to be no less stringent than current monitoring or reporting requirements;

(e) Allows for a change in ownership or operational control of a source if the Department has determined that no other change in the air quality operating permit is necessary, consistent with ARM 17.8.1225; or

(f) Incorporates any other type of change, which the Department has determined to be similar to those revisions set forth in (a)-(e), above.

"Applicable requirement" means all of the following as they apply to emission units in a source requiring an air quality operating permit (including requirements that have been promulgated or approved by the Department or the administrator through rule making at the time of issuance of the air quality operating permit, but have future-effective compliance dates, provided that such requirements apply to sources covered under the operating permit):

(a) Any standard, rule, or other requirement, including any requirement contained in a consent decree or judicial or administrative order entered into or issued by the Department, that is contained in the Montana state implementation plan approved or promulgated by the administrator through rule making under Title I of the FCAA;

(b) Any federally enforceable term, condition or other requirement of any Montana Air Quality permit issued by the Department under subchapters 7, 8, 9 and 10 of this chapter, or pursuant to regulations approved or promulgated through rule making under Title I of the FCAA, including parts C and D;

(c) Any standard or other requirement under Sec. 7411 of the FCAA, including Sec. 7411(d);

(d) Any standard or other requirement under Sec. 7412 of the FCAA, including any requirement concerning accident prevention under Sec. 7412(r)(7), but excluding the contents of any risk management plan required under Sec. 7412(r);

(e) Any standard or other requirement of the acid rain program under Title IV of the FCAA or regulations promulgated thereunder;

(f) Any requirements established pursuant to Sec. 7661c(b) or Sec. 7414(a)(3) of the FCAA;

(g) Any standard or other requirement governing solid waste incineration, under Sec. 7429 of the FCAA;

(h) Any standard or other requirement for consumer and commercial products, under Sec. 7511b(e) of the FCAA;

(i) Any standard or other requirement for tank vessels, under Sec. 7511b(f) of the FCAA;

(j) Any standard or other requirement of the regulations promulgated to protect stratospheric ozone under Title VI of the FCAA, unless the administrator determines that such requirements need not be contained in an air quality operating permit;

(k) Any national ambient air quality standard or increment or visibility requirement under part C of Title I of the FCAA, but only as it would apply to temporary sources permitted pursuant to Sec. 7661c(e) of the FCAA; or

(l) Any federally enforceable term or condition of any air quality open burning permit issued by the Department under subchapter 6.

"Department" means the Montana Department of Environmental Quality.

"Emission unit" means any part or activity of a stationary source that emits or has the potential to emit any regulated air pollutant or any pollutant listed under Sec. 7412(b) of the FCAA. This term is not meant to alter or affect the definition of the term "unit" for purposes of Title IV of the FCAA.

"FCAA" means the Federal Clean Air Act, as amended.

"Federally enforceable" means all limitations and conditions which are enforceable by the administrator, including those requirements developed pursuant to 40 CFR Parts 60 and 61, requirements within the Montana state implementation plan, and any permit requirement established pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR Part 51, Subpart I, including operating permits issued under an EPA approved program that is incorporated into the Montana state implementation plan and expressly requires adherence to any permit issued under such program.

"Fugitive emissions" means those emissions that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

"General air quality operating permit" or **"general permit"** means an air quality operating permit that meets the requirements of ARM 17.8.1222, covers multiple sources in a source category, and is issued in lieu of individual permits being issued to each source.

"Hazardous air pollutant" means any air pollutant listed as a hazardous air pollutant pursuant to Sec. 112(b) of the FCAA.

"Non-federally enforceable requirement" means the following as they apply to emission units in a source requiring an air quality operating permit:

(a) Any standard, rule, or other requirement, including any requirement contained in a consent decree, or judicial or administrative order entered into or issued by the Department, that is not contained in the Montana state implementation plan approved or promulgated by the administrator through rule making under Title I of the FCAA;

(b) Any term, condition or other requirement contained in any Montana Air Quality permit issued by the Department under subchapters 7, 8, 9 and 10 of this chapter that is not federally enforceable;

(c) Does not include any Montana ambient air quality standard contained in Subchapter 2 of this chapter.

"Permittee" means the owner or operator of any source subject to the permitting requirements of this subchapter, as provided in ARM 17.8.1204, that holds a valid air quality operating permit or has submitted a timely and complete permit application for issuance, renewal, amendment, or modification pursuant to this subchapter.

"Regulated air pollutant" means the following:

(a) Nitrogen oxides or any volatile organic compounds;

(b) Any pollutant for which a national ambient air quality standard has been promulgated;

(c) Any pollutant that is subject to any standard promulgated under Sec. 7411 of the FCAA;

(d) Any Class I or II substance subject to a standard promulgated under or established by Title VI of the FCAA; or

(e) Any pollutant subject to a standard or other requirement established or promulgated under Sec. 7412 of the FCAA, including but not limited to the following:

(i) Any pollutant subject to requirements under Sec. 7412(j) of the FCAA. If the administrator fails to promulgate a standard by the date established in Sec. 7412(e) of the FCAA, any pollutant for which a subject source would be major shall be considered to be regulated on the date 18 months after the applicable date established in Sec. 7412(e) of the FCAA;

(ii) Any pollutant for which the requirements of Sec. 7412(g)(2) of the FCAA have been met but only with respect to the individual source subject to Sec. 7412(g)(2) requirement.

"Responsible official" means one of the following:

(a) For a corporation: a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representative is approved in advance by the Department.

(b) For a partnership or sole proprietorship: a general partner or the proprietor, respectively.

(c) For a municipality, state, federal, or other public agency: either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a regional administrator of the environmental protection agency).

(d) For affected sources: the designated representative in so far as actions, standards, requirements, or prohibitions under Title IV of the FCAA or the regulations promulgated thereunder are concerned, and the designated representative for any other purposes under this subchapter.

Abbreviations:

ARM	Administrative Rules of Montana
ASTM	American Society of Testing Materials
BACT	Best Available Control Technology
BDT	bone dry tons
Btu	British thermal unit
CEMS	Continuous Emission Monitoring System
COMS	Continuous Opacity Monitoring System
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
dscf	dry standard cubic foot
dscfm	dry standard cubic foot per minute
EEAP	Emergency Episode Action Plan
EPA	U.S. Environmental Protection Agency
EPA Method	Test methods contained in 40 CFR 60, Appendix A
EU	emission unit
FCAA	Federal Clean Air Act
gr	grains
HAP	hazardous air pollutant
IEU	insignificant emission unit
Mbdft	thousand board feet
Method 5	40 CFR 60, Appendix A, Method 5
Method 9	40 CFR 60, Appendix A, Method 9
MMbdft	million board feet
MMBtu	million British thermal units
NO_x	oxides of nitrogen
NO_2	nitrogen dioxide
O_2	oxygen
Pb	lead
PM	particulate matter
PM_{10}	particulate matter less than 10 microns in size
psi	pounds per square inch
scf	standard cubic feet
SIC	Source Industrial Classification
SO_2	sulfur dioxide
SO_x	oxides of sulfur
tpy	tons per year
U.S.C.	United States Code
VE	visible emissions
VOC	volatile organic compound

APPENDIX C NOTIFICATION ADDRESSES

Compliance Notifications:

Montana Department of Environmental Quality
Permitting and Compliance Division
Air Resources Management Bureau
P.O. Box 200901
Helena, MT 59620-0901

DEQ - Air Resources Management Bureau
Airport Industrial Park 1P-9
1371 Rimtop Dr.
Billings MT 59105-1978

U.S. EPA Region VIII, Montana Office
Air Program Coordinator
Federal Office Building
10 West 15th Street, Suite 3200
Helena, MT 59626

Permit Modifications:

Montana Department of Environmental Quality
Permitting and Compliance Division
Air Resources Management Bureau
P.O. Box 200901
Helena, MT 59620-0901

Office of Partnerships and Regulatory Assistance
Air and Radiation Program
US EPA Region VIII 8P-AR
1595 Wynkoop Street
Denver, CO 80202-1129

APPENDIX D AIR QUALITY INSPECTOR INFORMATION

Disclaimer: The information in this appendix is not State or Federally enforceable but is presented to assist ConocoPhillips, permitting authority, inspectors, and the public.

1. **Direction to Plant:** 401 South 23rd Street, Billings Montana, 59103

2. **Safety Equipment Required:** ConocoPhillips has an extensive safety orientation package that inspectors and/or visitors must participate in.

   A safety video must be watched. Electronic Temporary Identification Cards are issued. Safety equipment such as fire-retardant coats, safety glass, ear plugs, H_2S monitors are all available for visitors. Steel-toed boots are optional but recommended when on site. Substantial footwear is required.

3. **Facility Plot Plan:** A facility plot plan was submitted with the original application on June 12, 1996.

APPENDIX E June 12, 1998 Board Order Adopting an SO_2 Control Plan

The June 12, 1998 Board Order Adopting and SO_2 Control Plan remain as applicable requirements as stated in the Title V Operating Permit OP2619-02. To receive a hard copy of this appendix, please contact one of the following:

Montana Department of Environmental Quality
Permitting and Compliance Division
Air Resources Management Bureau
1520 E. Sixth Ave.
P.O. Box 200901
Helena, Montana 59620-0901
Bureau Phone #: (406) 444-3490

OR

ConocoPhillips Company – Billings Refinery
P.O. Box 30198
401 South 23rd Street
Billings, MT 59107-0198
(406) 255-2580

APPENDIX F CAM Plan for Jupiter Sulfur Plant

Compliance Assurance Monitoring Plan

Jupiter Sulfur Plant, Billings MT

ConocoPhillips Billings Refinery, #OP2619-01

Particulate Filters for SRU/ATS Stack Effluent for PM-10 Control

The ConocoPhillips Billings Refinery (COP) and the Billings Jupiter Sulfur Plant have developed this Compliance Assurance Monitoring Plan (CAM Plan) for the particulate filters on the SRU/ATS process at the Jupiter Sulfur Plant located in Billings, Montana. The Jupiter Sulfur Plant in Billings is part of the COP Billings Refinery state preconstruction permit (currently #2619-21) and the COP Billings Refinery Title V Permit (#OP2619-01). The manager of the Billings Jupiter Sulfur Plant reports to the manager of the COP Billings Refinery, who is designated as the Responsible Official (RO) for the Title V permit.

A CAM Plan has been determined to be required for the particulate filters on the Billings Jupiter Sulfur Plant SRU/ATS process under the Montana CAM rule located in ARM Title 17, Chapter 8, Subchapter 15. This rule applicability is due to the following factors:

- The source (SRU/ATS process) is subject to a Title V permit
- The source is subject to an emission limit (PM-10, particulate matter less than 10 microns in diameter) that is federally-enforceable
- The source has potential PM-10 emissions greater than major source thresholds.
- The source uses a control device that is not inherent to the production process as the means to control PM-10 emissions
- The PM-10 emissions are not subject to emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to Section 111 (NSPS) or Section 112 (NESHAP/MACT) of the Clean Air Act
- The Part 70 permit (#OP2619-01) does not currently specify a continuous compliance determination method for PM-10 from the SRU/ATS stack

The SRU portion of the plant (Sulfur Recovery Unit) and the ATS portion of the plant (Ammonium Thiosulfate unit) are each equipped with two gas filters prior to discharging to the SRU/ATS stack. Because both portions of the plant are each equipped with two gas filters, a malfunctioning gas filter can be isolated and serviced while the process unit remains on-line.

The SRU/ATS stack has a PM-10 emission limit of 34.00 ton/yr, 186.3 lb/day, and 7.76 lb/hr (Condition H.7. of #OP2619-01). The SRU/ATS stack is due to be tested for PM-10 in late 2007. The most recent PM-10 test on the SRU/ATS stack was in October 2002. The average of the three test runs showed PM-10 emissions of 1.72 lb/hr. These results are well below the Title V permit limit of 7.76 lb/hr.

Compliance with the PM-10 emission limit contained within the ConocoPhillips Billings Refinery Title V permit for the Jupiter Sulfur ATS/SRU stack will be maintained by observing the pressure drop across the particulate filters. The pressure drop data will be recorded in the facility's Plant Information (PI) data management system, which will also provide for archiving of data.

Plant experience has shown that when the pressure drop across the Jupiter particulate filters decreases suddenly, a malfunction has likely occurred in one or more of the particulate filters. Previous particulate filter malfunctions have occurred when the filter medium is physically damaged or ruptured, such that the damage allows the process effluent stream to bypass the filter medium. When this occurs, the pressure drop across the filter medium decreases significantly and quickly.

When the data indicate that a pressure drop decrease has occurred that is outside the normal range of pressure drop data variability, the Jupiter operations personnel will make a visual observation of the SRU/ATS stack plume for confirmation of a particulate filter malfunction.

If the visual observation of the SRU/ATS stack plume confirms that a malfunction of the particulate filter has occurred, operations personnel must immediately begin to gather information for the purposes of diagnosing and correcting the cause of the malfunction. In addition, operations must, to the extent practicable, take steps to minimize emissions during these periods of particulate filter malfunction.

If the lack of ambient light and/or extremely cloudy conditions preclude the visual confirmation of a particulate filter malfunction, operations is to proceed under the assumption that a particulate filter malfunction has occurred, and must continue to gather information for the purposes of diagnosing and correcting the cause of the malfunction. In addition, operations must, to the extent practicable, take steps to minimize emissions during these periods of particulate filter malfunction or suspected particulate filter malfunction.

When the above-described malfunction or suspected malfunction occurs on the Jupiter particulate filters, the Jupiter operations personnel are to follow prescribed communication steps, which are outside the scope of this document.

APPENDIX G Alternate Operating Scenario - GOHDS Outage Plan

Gas Oil Hydrotreater Outage Plan

Revision 5.1

March 15, 2006

ConocoPhillips
Billings Refinery

Billings, Montana

15-Mar-06
Version 5

Introduction

In accordance with the Consent Decree between Conoco Inc. and the United States and certain States (Civil Action H-01-4430, as amended and entered on August 2, 2003), Conoco (now ConocoPhillips) submitted Gas Oil Hydrotreater (GOH) outage plans for the Billings Refinery to minimize emissions of NOx and SO_2 during GOH outages from the FCC unit. These were submitted to the EPA on June 17, 2002. The EPA responded in a letter dated March 1, 2005 that the plan did not meet their approval. The following GOH outage plan is submitted to address EPA comments and replaces the plan submitted previously.

SO_2 and NOx emissions from an FCCU primarily result from organic sulfur and nitrogen compounds in the FCCU feedstock. Hydrotreating the FCCU feed reduces the quantity of sulfur and nitrogen to the FCCU, thus potentially lowering the emissions of SO_2 and NOx. Because FCC Feed GO Hydrotreaters do not have 100% on stream efficiency, ConocoPhillips and EPA have agreed to a program to minimize FCCU emissions as much as practicable during GOH outages.

Paragraphs 27 and 41 of the Consent Decree stipulate that short-term NOx and SO_2 emission limits do not apply during GOH outages provided that ConocoPhillips:

- Maintain and operate the Billings Refinery FCCU in a manner consistent with good air pollution control practices for minimizing emissions during a GOH outage, and;
- Submit a plan for EPA approval that describes the steps that the Billings Refinery will take to minimize FCCU emissions in the event of a planned or unplanned GOH outage.
- Follow the submitted plan

Under the provisions of Paragraphs 27 and 41, ConocoPhillips reserves the right to propose alternative emissions limits and/or the exclusion of the NOx and SO_2 emissions during periods of GOH outages in the 365-day rolling average limit as part of the limit setting process in the Consent Decree.

For the purposes of this plan, a GOH outage or "Hydrotreater Outage" shall mean the period of time during which the operation of an FCCU is affected as a result of catalyst change-out operations or shutdowns required by ASME pressure vessel requirements or state boiler codes, or as a result of Malfunction, that prevents the hydrotreater from effectively producing the quantity and quality of feed necessary to achieve established FCCU emission performance. For purposes of this plan, a "planned outage" is one that is scheduled at least six months prior to a shutdown of the GOHDS unit and an "unplanned outage" is one that is either immediate or is scheduled for shutdown less than six months in advance.

ConocoPhillips has a strong incentive to plan GOH unit shutdowns properly due to the negative impact on FCCU yields and fuel specifications. As such, the Billings Refinery is motivated to minimize the impact of these events.

General Process Description

Sour Gas Oil – GOH Feedstock

Atmospheric gas oil is derived from crude distillation in the Billings Refinery's two Crude Units, vacuum gas oil is one of the products of the Vacuum Distillation Unit, and coker gas

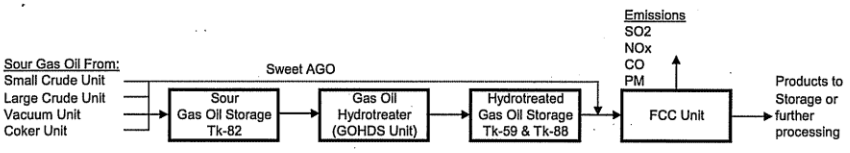
oil is obtained from the Coker Unit. Most of these gas oils are "sour" and contain relatively more sulfur than virgin gas oil derived from 100% sweet crude. The sour gas oils from the various sources are stored in the sour gas oil storage tank(s) and are the feedstock to the GOH unit. In general, sour gas oil storage is limited to one tank.

The GOH unit in the Billings Refinery is the No.4 Gas Oil Hydrotreater or GOHDS unit. The gas oil feeds to the GOHDS unit include virgin gas oils from the crude topping and vacuum units as well as coker gas oil from the Coker Unit. The GOHDS Unit uses catalytic hydrotreating technology to improve the quality of the FCC feed by removing sulfur, nitrogen, and organo-metallic compounds from sour feedstock and improving its cracking characteristics. The resulting GOHDS product is stored in hydrotreated gas oil storage tanks (Tk-59 & Tk-88) and make up most of the fresh feed to the FCCU. See Figure 1, the Billings Refinery Gas Oil System.

Sweet Gas Oil – FCC Feedstock

The Billings Refinery normally processes a blend of crudes; from sweet to sour, light to heavy. The sweetest gas oil (with the lowest sulfur) is the Small Crude Unit atmospheric gas oil (sweet AGO). This gas oil is routed directly to the FCC and normally makes up the remainder of fresh feed to the FCCU, as shown in Figure 1.

Figure 1
Block Flow Diagram - Billings Refinery Gasoil System



Other Feeds

Recently, the FCC has only processed hydrotreated gas oil and Small Crude Unit atmospheric gas oil as fresh feed. However, the FCC has processed sweet resid and various diesel-type streams in the past. If necessary, these feed streams may again need to be processed in the FCC if Refinery operation dictates. All emission permit limits will still be met while processing these "other" fresh feeds.

GOH Outage Plan

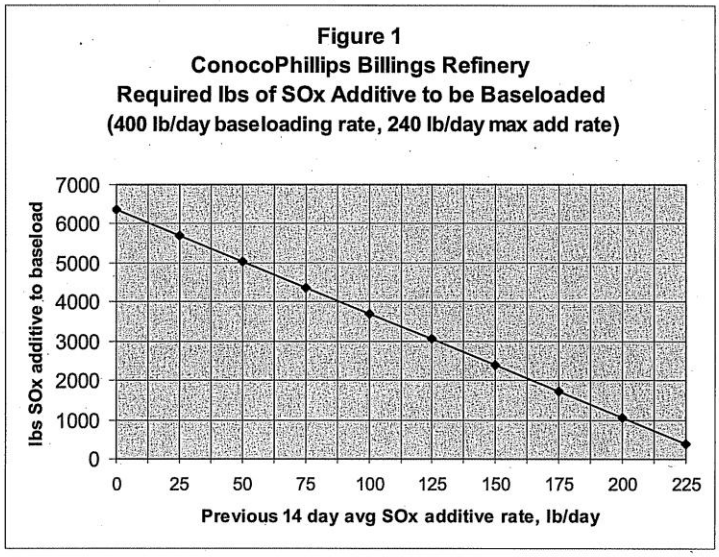
1. During the hydrotreater outage, the refinery can choose to continue to comply with the short term NOx and SO_2 short term limits established under the Consent Decree or alternatively under the terms of this GOH Outage Plan.

2. Planned GOH outages will be conducted concurrently with planned FCCU turnarounds to the extent practicable.

3. Prior to any planned GOH outage, the Billings Refinery will maximize inventory of hydrotreated and/or sweet gas oil to the extent practicable.

4. During a GOH outage, the Billings Refinery will use hydrotreated gas oil from inventory and sweet AGO, as available, to feed the FCCU in order to attempt to maintain FCCU SO_2 and NOx emissions below the short-term emissions limits established by the Consent Decree. If the amount of hydrotreated and/or sweet gas oil inventory is insufficient to maintain planned FCCU operations, then additional amounts of sour gas oils may be diverted to the FCCU as needed.

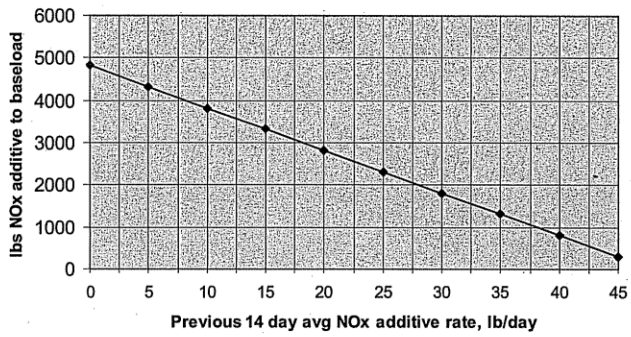
5. SO_2 Reducing Catalyst Additive Requirements - At the point where COP determines the short term SO_2 limit (50 ppmvd 0% O2, 7-day rolling average basis) may be exceeded, COP will immediately begin baseloading 400 lb/day of SO_2 additive. The total pounds of SO_2 additive to baseload shall be determined by Figure 1. Following completion of baseloading the required amount, COP shall continue to add a maximum addition rate of 240 lb/day of SO_2 additive for the remainder of the HDT outage regardless of actual SO_2 emissions.



6. NOx Reducing Catalyst Additive Requirements – Following the completion of the NOx additive demonstration period and the establishment of NOx limits, at the point where COP determines the short term NOx limit may be exceeded, COP will immediately begin baseloading 280 lb/day of NOx reducing catalyst additive. The total pounds of NOx additive to baseload shall be determined by Figure 2. Following completion of baseloading the required amount, COP shall continue to add a maximum addition rate of 48 lb/day of NOx additive for the remainder of the HDT outage regardless of actual NOx emissions. During the NOx additive demonstration period, COP will complete the

required baseloading prior to the start of any planned HDT Outage, or within 24 hours of the start of any unplanned HDT Outage, and shall maintain the maximum NOx addition rate for the entire HDT Outage. If the increased usage of NOx additive interferes with the effectiveness of the SO_2 reducing additive, COP may reduce NOx additive rate to a point where such interference does not exist and COP will notify EPA of such interference as soon as practicable. If COP demonstrates that the NOx additive interferes with the SO2 additive, the COP may request, and EPA may approve a modification to this NOx additive requirement during HDT outages.

Figure 2
ConocoPhillips Billings Refinery
Required lbs of NOx Additive to be Baseloaded
(280 lb/day baseloading rate, 48 lb/day max add rate)



7. To the extent that the Billings Refinery normally utilizes a low-NOx combustion promoter to minimize NOx emissions, the refinery shall continue to use such promoter during all GOH outages under the same conditions and constraints as for normal operation.

8. If either the SO_2 or NOx short term emission limits as determined per Consent Decree requirements are exceeded during a GOH outage, or if the GOH outage occurs during the NOx reducing catalyst additive demonstration period, then a report will be submitted to the EPA within 60 days after the end of the GOH outage. The report will identify the periods of time that the GOH outage plan applied rather than the short term limits, and describe the steps taken to comply with the GOH outage plan. The report will include data (compiled on a daily average basis) necessary to document that each requirement of the plan was implemented, and also include SO_2 and NOx stack concentration and mass rate emission data.

APPENDIX H - Summary of Terms and Conditions from the Consent Decree

The following summary of terms and conditions are from the Consent Decree (United States of America et al v. Conoco Inc., Civil Action H-01-4430 (Southern District of Texas, April 30, 2002). Although they are not terms and conditions of this Operating Permit, these terms and conditions may be enforced by the State of Montana and the United States Environmental Protection Agency pursuant to the provisions of the Consent Decree. These requirements are effective per the terms of the Consent Decree until Consent Decree termination and are summarized below.

FCCU Provisions

Pursuant to Paragraphs 8-30 for NOx emissions, ConocoPhillips was required to implement a multi-year program to evaluate the effectiveness of certain additives in reducing NOx emissions from the Billings Refinery FCCU. All portions of the NOx additive program have been implemented and the U.S. EPA and the refinery have verbally agreed on final NOx limits. ConocoPhillips is preparing a permit application to incorporate these agreed upon NOx limits into the appropriate permits.

Program requirements to establish FCCU SO_2 limits are also contained in the Consent Decree. (Paragraphs 31-41) Implementation of these requirements has resulted in final SOx limits which have been incorporated as final limits in the Title V permit.

Where the Consent Decree required the acceptance of a specific limit (i.e., for PM and CO) and/or CEMS installations, these limits have been incorporated specifically within the Title V permit and are not referenced in this Appendix.

Heater and Boiler Provisons

ConocoPhillips Company is required by the Consent Decree to realize SO_2 reductions from heaters and boilers across the Billings, Lake Charles and Ponca City refineries [Paragraphs 55(a)-68]. The Consent Decree allows COPC to determine where it would make such reductions so long as at least 30% of the fired duty of any given refinery was “controlled” as defined by the Consent Decree (Paragraphs 59 and 60). Reductions were realized at the Billings Refinery by the shutdown and dismantling of Heater H-1, pre-existing Boiler 5 and pre-existing Boiler 6. (Any references in the Title V pemit to Boilers 5 and 6 are to new, different boilers.) Another heater, H-9401, is equipped with ultra-low NOx burners (ULNB). The shutdowns and the existence of the ULNB on H-9401 satisified ConocoPhillips’ requirements that 30% of its firing capacity as it existed in 1999 at the Billings Refinery has been controlled. (Paragraphs 59 and 60). Requirements to properly operate and measure emissions from H-9401 are included in the Title V permit.

Sulfur Recovery Plant Optimization

During the life of the Consent Decree, ConocoPhillips shall continue to maintain its ConocoPhillips Sulfur Processing Best Practices Network as a means to optimize sulfur plant operations throughout the company including at the Billings Refinery (Paragraph 176). The network, at a minimum, will review:

(a) operator and engineer training for SRP and amine treating operations;
(b) operating parameters, material balances and efficiencies;
(c) acid gas and SWS gas composition;
(d) operating problems and corrective actions;
(e) incremental improvements achieved;
(f) new or modified operating procedures; and
(g) root cause and corrective action performed as a result of any incident investigation performed as a result of an Acid Gas Flaring Incident or Tail Gas Flaring Incident.

Control of Acid Gas Flaring Incidents and Tail Gas Incidents

ConocoPhillips shall implement procedures for evaluating whether future Acid Gas Flaring Incidents and Tail Gas Incidents are due to Malfunctions. The procedures shall require a Root Cause Failure Analysis and Corrective Action for flaring incidents as specified in the Consent Decree, and require stipulated penalties for Acid Gas Flaring Incidents or Tail Gas Incidents if the Root Causes were not due to Malfunctions.

Flaring Incidents Investigation and Reporting (Paragraph 183)
No later than forty-five (45) days following the end of an Acid Gas Flaring Incident, Tail Gas Incident or HC Flaring Incident (individually and collectively referred to as Flaring Incident), ConocoPhillips shall prepare a report that sets forth the information listed in paragraph 183 of the Consent Decree.

Corrective Action (Paragraphs 184 - 188)
In response to any Acid Gas Flaring Incident, Tail Gas Incident or HC Flaring Incident, ConocoPhillips shall take, as expeditiously as practicable, such interim and/or long-term corrective actions, if any, as are consistent with good engineering practice to minimize the likelihood of a recurrence of the Root Cause and all contributing causes of the subject incident.

If EPA and/or Montana DEQ do not notify ConocoPhillips in writing within 30 days of receipt of the report(s) required by Paragraph 183 that they object to one or more aspects of ConocoPhillips' proposed corrective action(s), if any, and schedule(s) of implementation, if any, then that (those) action(s) and schedule(s) shall be deemed acceptable for purposes of compliance with Paragraph 185 of the Consent Decree.

EPA and Montana DEQ do not, however, by their agreement to the entry of the Consent Decree or by their failure to object to any corrective action that ConocoPhillips may take in the future, warrant or aver in any manner that any of ConocoPhillips' corrective actions in the future will result in compliance with the provisions of the Clean Air Act, Montana Clean Air Act or their implementing regulations. Notwithstanding EPA's review of any plans, reports, corrective measures or procedures under Section J of the Consent Decree, ConocoPhillips shall remain solely responsible for compliance with the federal Clean Air Act, Montana Clean Air Act or their implementing regulations. Nothing in Section J of the decree shall be construed as a waiver of EPA's rights under the Clean Air Act and its regulations for future violations of the Act or its regulations nor to limit ConocoPhillips' right to take such corrective action as it deems necessary and appropriate immediately following a Flaring Incident or in the period during preparation and review of any reports required under Part X of the Consent Decree.

If the EPA does object, in whole or in part, to ConocoPhillips' proposed corrective action(s) and/or its schedule(s) of implementation, or, where applicable, to the absence of such proposal(s) and/or schedule(s), it shall notify ConocoPhillips of that fact within thirty (30) days following receipt of the report(s) required by Paragraph 183.

Nothing in Subsection J of the decree shall be construed to limit the right to take such corrective actions as it deems necessary and appropriate immediately following an Acid Gas Flaring incident or in the period during preparation and review of any reports required under this section of the Consent Decree.

Tail Gas Incidents – Investigation, Reporting, Corrective Action and Stipulated Penalties. (Paragraph 181 and 182)
For future Tail Gas Incidents, ConocoPhillips shall follow the same investigative, reporting, corrective action and assessment of stipulated penalty procedures as those outlined for Acid Gas Flaring Incidents. Those procedures shall be applied to TGTU shutdowns, bypasses of a TGTU, unscheduled shutdowns of a Sulfur Recovery Plant, or other miscellaneous unscheduled Sulfur Recovery Plant events which results in a Tail Gas Incident.

Control of Hydrocarbon Flaring Incidents

For future Hydrocarbon Flaring Events, ConocoPhillips shall follow the same investigative and corrective action procedures as those outlined for Acid Gas Flaring Incidents; except that ConocoPhillips shall only be required to submit such information to EPA and Montana DEQ in the Quarterly Reports required under Paragraph 183a. Stipulated penalties do not apply to Hydrocarbon Flaring Events.

Benzene Waste Operations NESHAP Program Enhancements

Refinery Compliance Status (Paragraphs 76-77)
ConocoPhillips' Billings Refinery is complying with the 6 BQ compliance option as set forth at 40 CFR 61.342(e). The Billings Refinery may not change its compliance option from the 6 BQ compliance option to the 2 Mg compliance option.

Review and Verification of TAB and Compliance with 6 BQ Compliance Option (Paragraphs 78 - 80)
On September 30, 2002, ConocoPhillips' Billings Refinery submitted its BWON Compliance Review and Verification Report. This report identified the facility's waste streams, TAB calculations, benzene concentrations and control status as required by Paragraph 78(a) through (d). EPA did not require any additional sampling or studies.

Waste/Slop Oil Management (Paragraph 81)
On Dec. 5, 2002, the Billings Refinery submitted its waste/slop oil management plan. This plan was approved by EPA on October 28, 2003.

Carbon Canisters Paragraphs 87-96)
The Billing Refinery is required to comply with specific requirements for the use of carbon canisters as BWON control devices. Generally, dual canisters operating in series are required and the secondary canister must be replaced upon breakthrough.

Annual Review (Paragraph 97)
ConocoPhillips must annually review refinery process and project to ensure that all new benzene waste streams are included in the Billings Refinery's waste stream inventory during the life of the Consent Decree.

Laboratory Audits (Paragraphs 98-100)
ConocoPhillips shall conduct audits of all laboratories that perform analyses of ConocoPhillips' benzene waste operations NESHAP samples to ensure that proper analytical and quality assurance/quality control procedures are followed. These audits may be conducted by either ConocoPhillips personnel or third parties. ConocoPhillips may rely upon audit results obtained by another company that has similar audit requirements if that company has audited the same laboratory within the past twelve (12) months. ConocoPhillips shall audit any new laboratory used for analyses of benzene samples prior to use of the new laboratory. During the life of the Consent Decree, ConocoPhillips shall conduct subsequent laboratory audits, such that each laboratory is audited every two (2) years.

Spills (Paragraph 101)
ConocoPhillips shall review reportable spills at the Billings Refinery to determine if benzene waste, as defined under Subpart FF, was generated. For the purposes of this review, reportable will be the smaller of the benzene quantity defined as reportable by either CERCLA or the State in which the particular refinery operates. ConocoPhillips shall account for such benzene waste in the TAB for the Billings Refinery as required by 40 CFR 61.342.

Training (Paragraphs 102-105)
ConocoPhillips shall conduct annual (i.e.: once each calendar year) training for all employees asked to draw benzene waste samples. Training specific to the Refinery's BWON equipment and operating procedures is required every three years. Contractors are responsible for training their own employees. If personnel are employees of contractors, the contractor will provide their employees' training information to ConocoPhillips.

End of Line Sampling (6 BQ Compliance Option) (Paragraphs 108-110)
The Billings Refinery submitted a sampling plan on December 5, 2002. This plan was approved on October 28, 2003. Per the plan, the refinery conducts quarterly sampling at specified points throughout the refinery and of all uncontrolled streams to estimate compliance with the annual TAB limit.

Quarterly Estimations of Annual TAB (Paragraphs 115-116)
Using data collected per the sampling plan (Paragraph 108-110) ConocoPhillips shall calculate a quarterly and estimate a calendar year value. If the either the quarterly calculation made pursuant to Paragraph 115 exceeds 1.5 mg or the annual estimate exceeds 6 BQ, then ConocoPhillips shall prepare a written summary and schedule of the activities planned to minimize benzene wastes for the rest of the calendar year to ensure that the calendar year calculation complies with the 6 BQ compliance option. The summary and schedule are due no later than sixty (60) days after the close of the quarter in which the quarterly calculation exceeded the applicable quantity.

Miscellaneous Measures (paragraph 117)
The Billings Refinery is required to implement certain measures to enhance its compliance with the BWON requirements. These measures include additional visual inspections of water traps in the individual drain systems, vents on process sewers and the oil-water separators. Additionally, all segregated storm water drains must be marked as such,

Recordkeeping and Reporting Requirements (Paragraph 131)
In addition to the reports required under 40 CFR 61.537, the facility must submit the various reports and calculations noted above. These additional reports are due, as noted in the Consent Decree, either by the date specified in the Consent Decree or with the Progress Reports required under the Consent Decree.

Leak Detection and Repair ("LDAR") Program Enhancements

The following requirements are enhancements to the existing refinery LDAR program. The existing refinery LDAR program includes the requirements of 40 CFR Part 60 Subpart GGG and VV; Part 61, Subparts J and V; and Part 63 Subparts F, H and CC and applicable state LDAR requirements.

Written Refinery-Wide LDAR Program (Paragraph 126)
ConocoPhillips shall maintain a written refinery-wide program for compliance with all applicable federal and state LDAR regulations. Until termination of this Decree, ConocoPhillips shall implement the program on a refinery-wide basis and update the program as necessary to ensure continuing compliance. The refinery-wide program shall include the items listed in Paragraph 126 of the Consent Decree.

Training (Paragraph 127)
ConocoPhillips shall maintain the training program described in Paragraph 127 of the Consent Decree.

Valves Not Included in the Monitoring Program as of 9/30/03 (Paragraph 140.a.)
ConocoPhillips shall monitor valves in light-liquid and/or gaseous service which were not included in the existing refinery LDAR program at least annually, shall repair leaks identified under this subparagraph in accordance with the requirements of other, regulated valves, and shall maintain all records for valves monitored and repaired under this subparagraph in accordance with the requirements of other, regulated valves.

LDAR Audits (Paragraphs 128-131)
ConocoPhillips shall implement refinery-wide LDAR audits as set forth in Paragraphs 129-130 of the Consent Decree to ensure the refinery's compliance with all applicable LDAR requirements. The audits shall include but not be limited to, comparative monitoring, records review, tagging, data management and observation of the LDAR technicians' calibration and monitoring techniques. An audit of the refinery shall occur every two years and, shall alternate between third party led audits and ConocoPhillips' led audits. . As an alternative to the ConocoPhillips' led audits, ConocoPhillips may elect to retain third parties to undertake these audits.

Actions Necessary to Correct Non-Compliance (Paragraph 132-133)
If the results of any of the audits identify any areas of non-compliance, ConocoPhillips shall implement, as soon as practicable, all steps necessary to correct the area(s) of non-compliance, and to prevent, to the extent practicable, a recurrence of the cause of the non-compliance. Until two (2) years after the termination of the Consent Decree, ConocoPhillips shall retain the audit reports generated pursuant to Paragraphs 129-130 of the Consent Decree and shall maintain a written record of the corrective actions that ConocoPhillips takes in response to any deficiencies identified in any audits. In the quarterly report submitted pursuant to the provisions of Part XIV of the Consent Decree (Recordkeeping and Reporting) for the first calendar quarter of each year, ConocoPhillips shall report on the audits and corrective actions for audits performed during the previous year.

Internal Leak Definition for Valves and Pumps (Pumps (Paragraphs 134-135)
The permittee shall utilize the following internal leak definitions, unless other permit(s), regulations, or laws require the use of lower leak definitions.

Leak Definition for Valves: 500 ppm VOCs for all valves in light liquid and/or gas vapor service, excluding pressure relief devices.

Leak Definition for Pumps: 2,000 ppm for pumps in light liquid and/or gas/vapor service.

Reporting, Recording, Tracking, Repairing and Re-monitoring Leaks of Valves and Pumps Based on the Internal Leak Definitions (Paragraphs 137-138)
Reporting: For regulatory reporting purposes, ConocoPhillips may continue to report leak rates in valves and pumps against the applicable regulatory leak definition, or may use the lower, internal leak definitions specified in paragraphs 135 and 136. The permittee will identify in the report which definition is being used.

Recording, Tracking, Repairing and Re-monitoring Leaks: ConocoPhillips shall record, track, repair and re-monitor applicable leaks in excess of the internal leak definitions of paragraphs 135 and 136 (at such time as those definitions become applicable), except that ConocoPhillips shall have 30 days to make repairs and re-monitor leaks that are greater than the internal leak definitions but less than the applicable regulatory leak definitions.

First Attempt at Repairs on Valves (Paragraph 139)
ConocoPhillips shall promptly make a "first attempt at repair" on any valve that has a reading greater than 200 ppm of VOCs excluding valves, pumps and components that LDAR personnel are not authorized to repair. The timing for the "first attempt at repair" of those components which monitoring personnel are not authorized to repair will be consistent with the existing regulatory requirements. "First attempt at repair" will be made promptly (no later than next business day) for the valves over 200 ppm that the LDAR monitoring personnel are authorized to attempt repair. The "first attempt at repair" will be re-monitored no later than four business days following the repair to assure the leak is not worse. No other action will be required unless the leak exceeds the then-applicable leak definition.

LDAR Monitoring Frequency (Paragraph 140-141)
Pumps: When the lower leak definition for pumps becomes applicable pursuant to Paragraph 136, ConocoPhillips shall monitor pumps in light liquid and/or gas/vapor service at the lower leak definition on a monthly basis.

Valves: Unless more frequent monitoring is required by state regulation when the lower internal leak definition for valves becomes applicable pursuant to paragraph 135, ConocoPhillips shall monitor valves in light liquid and/or gas vapor service – other than difficult to monitor or unsafe to monitor valves – on a quarterly basis, with no ability to skip periods on a process-unit-by-process-unit basis.

Electronic Monitoring, Storing, and Reporting of LDAR Data (Paragraphs 142-143)
Electronic Storing and Reporting of LDAR Data: ConocoPhillips has and will continue to maintain for the duration of this Consent Decree an electronic database for storing and reporting LDAR data.

Electronic Data Collection During LDAR Monitoring: For the duration of this Consent Decree, ConocoPhillips shall continue to use data loggers and/or electronic data collection devices during LDAR monitoring. ConocoPhillips, or its designated contractor, shall use its/their best efforts to transfer, on a daily basis, electronic data from electronic data logging devices to the electronic database of Paragraph 142. For all monitoring events in which an electronic data collection device is used, the collected monitoring data shall include a time and date stamp, and instrument and operator identification. ConocoPhillips may use paper logs where necessary or more feasible (e.g., small rounds, re-monitoring, or when data loggers are not available or broken), and shall record, at a minimum, the identification of the technician undertaking the monitoring, the date, and the identification of the monitoring equipment. ConocoPhillips shall transfer any manually recorded monitoring data to the electronic database of Paragraph 142 within seven (7) days of monitoring.

QA/QC of LDAR Data (Paragraph 144)
ConocoPhillips, or a third party contractor retained by ConocoPhillips, shall develop and implement a procedure to ensure a quality assurance/quality control ("QA/QC") review of all data generated by LDAR monitoring technicians. This QA/QC procedure shall include the procedures as set forth in paragraph 144 of the Consent Decree.

Calibration/Calibration Drift Assessment (Paragraphs 145-146)
Calibration: ConocoPhillips shall conduct all calibrations of LDAR monitoring equipment using methane as the calibration gas, in accordance with 40 CFR Part 60, EPA Reference Test Method 21.

Calibration Drift Assessment: ConocoPhillips shall conduct calibration drift assessments of LDAR monitoring equipment at the end of each monitoring shift, at a minimum. ConocoPhillips shall conduct the calibration drift assessment using, at a minimum, a 500 ppm calibration gas. If any calibration drift assessment after the initial calibration shows a negative drift of more than 10% from the previous calibration, ConocoPhillips shall re-monitor all valves that were monitored since the last calibration that had a reading greater than 100 ppm and shall re-monitor all pumps that were monitored since the last calibration that had a reading greater than 500 ppm.

Delay of Repair (Paragraph 147-149)
For any equipment for which ConocoPhillips is allowed, under 40 CFR 60.482-9(a) or equivalent state regulation, to place on the "delay of repair" list for repair, ConocoPhillips shall: Require sign-off by the unit supervisor, which position shall be identified in the written program that the piece of equipment is technically infeasible to repair without a process unit shutdown, before the component is eligible for inclusion on the "delay of repair" list; and include equipment that is placed on the "delay of repair" list in ConocoPhillips' regular LDAR monitoring. For leaks above the internal leak definition rate and below the regulatory rate, ConocoPhillips shall have 30 days to put the equipment on the delay of repair list.

For valves, other than control valves or pressure relief valves that qualify to be on the "delay of repair" list and are leaking at a rate of 50,000 ppm or greater, ConocoPhillips will undertake "extraordinary efforts" to fix the leaking valve rather than keeping the valve on the "delay of repair" list, unless ConocoPhillips can demonstrate that there is a safety, mechanical, or major environmental concern posed by repairing the leak in that manner. For valves, extraordinary effort will be undertaken within 120 days of the valve being placed on the "delay of repair" list.

After two unsuccessful attempts to repair a leaking valve through the drill and tap method, ConocoPhillips may keep the leaking valve on its "delay of repair" list. ConocoPhillips will implement these extraordinary repair procedures within 30 days of completion of the written program. ConocoPhillips will also make extraordinary efforts to repair those valves which have been placed on the delay of repair list which leak at 10,000 ppm for more than three years. ConocoPhillips may delay these repairs further if it can demonstrate that there is a safety, mechanical or major environmental concern posed by repairing the leak in this manner.

Recordkeeping and Reporting Requirements (Paragraphs 151-153)
Quarterly Progress Report for the First Calendar Quarter of Each Year – Reporting on Audits: ConocoPhillips will report on the audits and corrective actions (Paragraphs 128 – 133) in the quarterly progress report that ConocoPhillips submits for the first calendar quarter of each year pursuant to Part XIV of the Consent Decree. For the remainder of the audits required pursuant to the Consent Decree, in the quarterly progress report that ConocoPhillips submits for the first calendar quarter of each year, ConocoPhillips shall identify the auditors, identify that a written plan exists identifying corrective action for any deficiencies identified in the audits and that this plan is being implemented.
Reports due under 40 CFR 63.654: In each report due under 40 CFR 63.654, ConocoPhillips shall include the information included in Paragraph 151 of the Consent Decree.

Agencies to Receive Reports, Plans and Certifications Required in the Part IX; Number of Copies (Paragraph 153)
ConocoPhillips shall submit all reports, plans and certifications required to be submitted under Paragraphs 150 – 151 to EPA and the state agency. Upon written agreement of the parties, ConocoPhillips may submit the materials electronically.

Reporting and Recordkeeping

Recordkeeping: Per Paragraph 211, Conoco shall retain all records required to be maintained in accordance with this Consent Decree for a period of five (5) years after termination of the Consent Decree, unless other regulations require the records to be maintained longer. Per Paragraph 21, reports required to be certified must include a specific certification.

Reporting: Paragraph 213, 213A, and 213B require ConocoPhillips to provide specific information in the semi-annual reports it submits to EPA and Montana DEQ. Each semi-annual report will contain:

(a) Progress report on the implementation of the requirements of Parts IV - XII at the relevant Refinery;

(b) A summary of the emissions data and Hydrocarbon Flaring Incidents for the relevant Refinery that is specifically required by the reporting requirements of Parts IV-XII and XIV of this Consent Decree for the period covered by the report;

(c) A description of any problems anticipated with respect to meeting the requirements of Parts IV-XII of this Consent Decree at the relevant Refinery;

(d) A description of the status of all SEPs/BEPs (if any) being conducted at the Refinery;

(e) Any such additional matters as the Company believes should be brought to the attention of EPA and the Applicable Plaintiff-Intervene; and

(f) Any emission exceedances and/or CEMS downtime that occurred during the reporting period.

Additionally, in the semi-annual report required to be submitted on July 31 of each year, the Company shall provide a summary of annual emissions data for the prior calendar year to include:

(a) NOx, SO_2, CO and PM emission tons per year for each heater and boiler greater than 40 mmBTU/hr maximum fired duty;

(b) NOx, SO_2, CO and PM emission in tons per year for each FCCU;

(c) SO_2 emissions from all Sulfur Recovery Plants in tons per year;

(d) SO_2 emissions from all acid gas flaring and tail gas incidents by flare in tons per year; and

(e) NOx, SO_2, PM and CO emissions in tons per year as a sum at each refinery for all other emissions units for which emissions information is required to be included in the facilities' annual emissions summaries and are not identified in (a) through (d) and (f) of this paragraph;

(f) NOx, SO_2, CO and PM emission in tons per year as a sum for all heaters and boilers less than 40 mmBTU/hr maximum fired duty; and

(g) For each of the estimates in (a) through (d) above, the basis for the emissions estimate or calculation (i.e. stack tests, CEMS, emission factor, etc.).

To the extent that the required emissions summary data is available in other reports generated by the Company, such other reports can be attached, or the appropriate information can be extracted from such other reports and attached to this semi-annual report to satisfy this requirement. Company may submit a written request to EPA to stop supplying Paragraph 213A reports, and if EPA approves this request in writing, Company shall no longer be required to provide such reports.