Air, Energy & Mining Division

Date of Posting: July 2, 2025

Name of Permittee: Phillips 66 Company

Facility Name: Billings Refinery

Physical Site Location (Address): Section 2, Township 1 South, Range 26 East

Sent via email: Duncan.crosbie@p66.com

RE: Preliminary Determination on Montana Air Quality Permit Application #2619-46

Proposed Action: The Montana Department of Environmental Quality (DEQ) proposes to issue a permit, with conditions, to the above-named applicant. The application has been assigned Montana Air Quality Permit (MAQP) Application #2619-46.

Proposed Conditions: See attached Preliminary Determination on MAQP #2619-46.

Public Comment: Any member of the public desiring to comment must submit comments to DEQAir@mt.gov or to the address below. Comments may address DEQ's analysis and Preliminary Determination (PD), Draft Environmental Assessment (Draft EA), or the information submitted in the application. All comments are due by July 17, 2025. Copies of the application, the PD, including the Draft EA, and DEQ's permit analysis may be requested at https://deq.mt.gov (at the bottom of the home page, select *Request Public Records)*. For more information, contact DEQ at (406) 444-3490, or DEQAir@mt.gov.

Department Action: DEQ intends to make a Decision on the application following the public comment period. A copy of the Decision will be available on DEQ's website, https://deq.mt.gov/public/publicnotice (select *AIR)*. The permit shall become final and effective on the date stated in the Decision, unless the Board of Environmental Review (Board) orders a stay on the permit.

Procedures for Appeal: Any person who is directly and adversely affected by DEQ's Decision may request a hearing before the Board. The appeal must be filed by the date that will be stated in the Decision. The request for a hearing must contain an affidavit setting forth the grounds for the request. The hearing will be held under the provisions of the Montana Administrative Procedures Act. Submit requests for a hearing to: Chairman, Board of Environmental Review, P.O. Box 200901, Helena, MT 59620, or the Board Secretary: DEQBERSecretary@mt.gov.

For DEQ,

Eric Merchant, Supervisor
Air Quality Permitting Services Section
Air Quality Bureau
Air, Energy, and Mining Division
(406) 444-3626
eric.merchant2@mt.gov

John P. Proulx
Air Quality Engineer
Air Quality Bureau
Air, Energy, and Mining Division
(406) 444-5391
jproulx@mt.gov

MONTANA AIR QUALITY PERMIT

Issued to:	Phillips 66 Company Billings Refinery P.O. Box 30198 Billings, MT 59107-0198	MAQP: #2619-46 Application Complete: 05/28/2025 Preliminary Determination: 07/02/2025 Department Decision: Permit Final:

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to Phillips 66 Company (Phillips 66), pursuant to Sections 75-2-204, 211, 213, and 215 of the Montana Code Annotated (MCA), as amended, and the Administrative Rules of Montana (ARM) 17.8.740, *et seq*., and 17.8.801, *et seq*., as amended, for the following:

SECTION I: Permitted Facility

A. Plant Location

Phillips 66 operates a petroleum refinery located at 401 South 23rd Street, Billings, Montana, in the NW¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County. A complete list of the permitted equipment for Phillips 66 is contained in Section I.A of the Permit Analysis.

B. Refinery Operations

Phillips 66 operates a petroleum refinery, with those operations covered under this MAQP. The refinery operations at the source were provided a separate Title V Operating Permit for purposes of facilitating Responsible Official responsibilities in line with management structure. For Prevention of Significant Determination (PSD)/New Source Review (NSR), New Source Performance Standards (NSPS), Maximum Achievable Control Technology (MACT) permit review purposes and Title V applicability purposes, the Refinery Operations are considered the same source as the Phillips 66 Pipeline, LLC Transportation Operations and Jupiter Sulphur, LLC Operations.

C. Transportation Operations – Phillips 66 Pipeline, LLC

Phillips 66 owns Phillips 66 Pipeline, LLC, which operates loading rack operations adjacent to the refinery operations that are covered under this MAQP. The portions of the source under the management of the Transportation Operations were provided a separate Title V Operating Permit for purposes of facilitating Responsible Official responsibilities in line with management structure. For PSD/NSR, NSPS, MACT, and Title V applicability purposes, the Transportation Operations, Refinery Operations, and Sulfur Recovery Operations are considered one source.

D. Sulfur Recovery Operations - Jupiter Sulphur, LLC (Jupiter)

Jupiter is a sulfur recovery operation within the petroleum refinery area described above at 2201 7th Avenue South, Billings, Montana. This operation is a joint venture, of which Phillips 66 is a partner.

With physical changes required at the Jupiter plant in order for operational goals and changes within the refinery to be achieved, air quality permit actions have been submitted and accepted as being one source. The Jupiter sulfur recovery operations consists of three sulfur recovery units. The Jupiter operations are covered under this MAQP and are currently a part of the Refinery Operations Title V Operating Permit. For PSD/NSR, NSPS, MACT, and Title V applicability purposes, the Jupiter operations are considered part of the same source as the Transportation and Refinery Operations.

E. Current Permit Action

On May 21, 2025, the Department of Environmental Quality (DEQ) received an application from Tetra Tech, on behalf of Phillips 66, to modify their MAQP. The modification requests an increase in throughtput of gas oil to the Fluidized Catalytic Cracking Unit (FCCU) from 24,000 barrels per day (bpd) to 26,000 bpd. Phillips 66 also requested the removal of the No. 3 H_2 Plant Reformer Heater and No. 3 H_2 Plant PSA Off-Gas Vent.

The proposed changes addressed by this permit action demonstrate an increase in annual emission rates for PM_{10}, $PM_{2.5}$, SO_2, and VOCs. The proposed emissions increases under the current permit action do not exceed applicable significant emission rates (SER) listed in ARM 17.8.801(28) for any of these pollutants and thus additional analysis is not explicitly required. Further, modeling thresholds and major New Source Review, Prevention of Significant Deterioration (PSD) review have previously been triggered for both PM_{10} and $PM_{2.5}$ and Phillips 66 has demonstrated emissions from the proposed project would comply with the national ambient air quality standards (NAAQS) for PM_{10} and $PM_{2.5}$. However, for consistency and clarity, Phillips 66 chose to conduct updated modeling for particulate matter (PM_{10}, $PM_{2.5}$) to supplement and demonstrate ongoing compliance with previously submitted PSD analyses.

SECTION II: Conditions and Limitations

A. Applicable Requirements

1. Phillips 66 shall comply with all applicable requirements of ARM 17.8.340, which references 40 Code of Federal Regulations (CFR) Part 60, Standards of Performance for New Stationary Sources (NSPS):

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

   b. Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units shall apply to all affected boilers at the facility which were constructed after June 19, 1984, are larger than 100 million British thermal units per hour (MMBtu/hr), and combust fossil fuel. Phillips 66 shall comply with all applicable requirements of Subpart Db, for all affected boilers at the facility which includes Boilers B-5 and B-6.

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

   i. All of the heaters and boilers at the Phillips 66 refinery not subject to or electing to comply with Subpart Ja (ARM 17.8.749);

   ii. The Fluid Catalytic Cracking Unit (FCCU) (CO, SO_2, PM, and opacity provisions) (ARM 17.8.749); and

   iii. Any other affected equipment.

d. Subpart Ja - Standards of Performance for Petroleum Refineries for which Construction, Reconstruction, or Modification commenced after May 14, 2007, shall apply to, but not be limited to:

   i. The Delayed Coking Unit (Delayed Coker) (ARM 17.8.340 and 40 CFR 60 Subpart Ja)

   ii. Refinery Main Plant Relief Flare (ARM 17.8.340 and 40 CFR 60 Subpart Ja)

   iii. Jupiter SRUs and Flare (ARM 17.8.340, and 40 CFR 60 Subpart Ja)

   iv. The following process heaters: Vacuum Furnace H-17, Large Crude Unit Heater H-24 (ARM 17.8.340 and 40 CFR 60 Subpart Ja).

   v. Any other affected equipment

e. Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids shall apply to all petroleum storage vessels for which construction, reconstruction or modification commenced after May 18, 1978, and prior to July 23, 1984, for requirements not overridden by 40 CFR 63 Subpart CC.

   These requirements shall be as specified in 40 CFR 60.110a through 60.115a. The affected tanks include, but are not limited to, the following:

   <u>Tank ID</u>
   i. T-100*
   ii. T-101*
   iii. T-102

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

** *MACT Refinery I Group 1 storage vessels subject to 40 CFR 63 Subpart CC and 40 CFR Subpart Ka, are only required to comply with the requirements of 40 CFR 63 Subpart CC according to 40 CFR 63.660(n)(5). Additionally, MACT Refinery Group 1 tanks subject to 40 CFR 63 Subpart CC shall comply with the requirements of 40 CFR 63 Subpart WW per 40 CFR 63.660.*

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

<u>Tank ID</u>

i. T-35
ii. T-72
iii. T-107*
iv. T-110
v. T-0851 (No. 5 HDS Feed Storage Tank)
vi. T-1102 (Crude Oil Storage Tank)
vii. T-2909 (LSG Tank)

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

** *MACT Refinery Group 1 tanks subject to 40 CFR 63 Subpart CC shall comply with the requirements of 40 CFR 63 Subpart WW per 40 CFR 63.660.*

g. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006 shall apply to the following compressors:

i. C-26, FCCU Wet Gas Compressor

ii. C-3901, Coker Unit Wet Gas Compressor

iii. C-5301, Flare Gas Recovery Unit Liquid Ring Compressor

iv. C-5302, Flare Gas Recovery Unit Liquid Ring Compressor

v. C-8301, Cryo Unit Inlet Gas Compressor

vi. C-8302, Cryo Unit Refrigerant Compressor

vii. C-8303, Cryo Unit Regeneration Gas Compressor

viii. C-9401, No. 1 H_2 Plant Feed Gas Compressor

ix. C-9701, No. 2 H_2 Plant Feed Gas Compressor

h. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006 shall apply to the following compressors which are in hydrogen service:

i. C-8401, No. 4 HDS Makeup/Recycle H_2 Compressor

ii. C-7401, H_2 Makeup/Reformer H_2 Compressor

iii. C-9501, Makeup/Recycle Gas Compressor

iv. C-27, Butamer Combined Hydrogen Compressor

v. C-19, No. 2 Reformer Recycle Hydrogen Compressor

vi. C-18, No. 2 HDS Recycle Hydrogen Compressor

vii. C-8402, Makeup/Recycle Compressor

i. Reserved

j. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 shall apply to, but not be limited to the group of all equipment (as defined in 40 CFR 60.591a) in the following process units:

i. Delayed Coker Unit

ii. Cryogenic Unit

iii. Hydrogen Membrane Unit

iv. Gasoline Merox Unit

v. Crude Units

vi. Gas Oil Hydrotreater Unit (consisting of a reaction section, fractionation section, and an amine treating section)

vii. No. 1 H_2 Unit (22.0-million standard cubic feet per day (MMscfd) hydrogen plant feed system)

viii. Alkylation Unit (including the and the Alkylation Unit Depropanizer Project)

ix. #3 Sour Water Stripper (SWS) Unit

x. Fugitive components associated with boilers #B-5 and #B-6

xi. Fugitive components associated with the No.2 H2 Unit and the No.5 HDS Unit

xii. FCCU

xiii. Any other applicable equipment constructed or modified after November 7, 2006

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

i. Coker unit drain system

ii. Desalter wastewater break tanks

iii. Gas oil hydrotreater oily water sewer drain system

iv. No. 1 H_2 Plant (22.0-MMscfd H_2 plant)

v. Alkylation Unit Butane Defluorinator oily water sewer drain system

vi. Alkylation Unit Depropanizer oily water sewer drain system

vii. #3 SWS Unit oily water sewer drain system

viii. South Tank Farm oily water sewer drain system

ix. Tank T-4523 (wastewater surge tank)

x. API Separators, including the slop oil vessel T-4526 and Sludge Hopper T-4527.

xi. No. 2 H_2 Plant and the No. 5 HDS Unit new individual oily water drain system

xii. Any other applicable equipment, for requirements not overridden by 40 CFR 63 Subpart CC

l. Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines shall apply to, but not be limited to diesel-fired engines used for operation of the Backup Coke Crusher, the Backup Firepump Engine, and the Emergency Generator Engine (G-8401) for the HDS Flare Drum Pumps.

2. Phillips 66 shall comply with all applicable requirements of ARM 17.8.341, which references 40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAP):

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

   b. Subpart FF - National Emission Standards for Benzene Waste Operations shall apply to, but not be limited to, all new or recommissioned wastewater sewer drains associated with the Alkylation Unit Depropanizer Project, the Refinery's existing individual drain and sewer systems (except the Alky grandfathered sewers), the new individual drain system and Tanks 34 and 35.

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

3. Phillips 66 shall comply with all applicable requirements of ARM 17.8.342, which reference 40 CFR Part 63, NESHAP for Source Categories, including the reporting, recordkeeping, testing, and notification requirements:

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

   b. Subpart Q – National Emissions Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers applies only if chromium based water treatment chemicals are used. The rule bans chromium based water treatment chemicals from being used.

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

   d. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (Refinery MACT I), shall apply to, but not be limited to, Miscellaneous Process Vents; Equipment Leaks; Wastewater Streams; Heat Exchange Systems, and Storage Vessels including but not limited to:

      Group 1:
      - Crude Oil Storage Tanks #1, #2, and T-1102
      - Gasoline, Naphtha, and Other Storage Tanks: #3, #5, #7, #9, #11, #12, #16, #21, #41, #42, #45, #46, #49, #52, #55, #72, #75, #80, #86, #87, #102, #110, #851, #2909

      Group 2:
      - Asphalt and PMA Storage Tanks #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, #107, #T-0852
- Other Storage Tanks #13, #18, #32, #59, #60, #82, #88, #116, #801
- Organic Liquid Distribution (OLD) MACT:
    - Tank #109

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

f. Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines shall apply to, but not be limited to the diesel-fired engine used for operation of the Backup Coke Crusher, the Cryo Backup Air Compressor engine, the Boiler House Air Compressor engine, the Pump for Storm Water to Holding Pond engine, the Backup Firepump Engine, the Emergency Generator Engine (G-8401) for the HDS Flare Drum Pumps, and the Boiler House Backup Air Compressor engine.

g. Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Applicability includes the boilers and fuel gas combustion units.

h. 40 CFR 63 Subpart WW – National Emission Standards for Storage Vessels (Tanks) – Control Level 2. Applicability includes storage vessels for which another Subpart references the use of this Subpart for such air emission control.

4. Phillips 66 shall comply with the provisions of 40 CFR 82 Subpart F, Recycling and Emission Reduction as applicable (ARM 17.8.749).

B. Emission Control Requirements

Phillips 66 shall install, operate, and maintain the following emission control equipment to provide the maximum air pollution control for which it was designed (ARM 17.8.752):

1. The Refinery Main Plant Relief flare must be equipped and operated with a steam injection system (ARM 17.8.752). The flare tip is to be based at a minimum of 142-feet plus or minus 2 feet elevation (ARM 17.8.749). Phillips 66 shall minimize SO_2 flaring activity by installing and operating flare gas recovery systems on the Refinery Main Plant Relief flare (ARM 17.8.749).

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

3. Phillips 66 shall utilize, as needed, CO combustion promoter, NO_X reducing catalyst additive, and SO_2 reducing catalyst additive in the FCCU catalyst regenerator, hydrotreating of the feed to the FCCU, as well as CO, NO_X, SO_2, and O_2 CEMS, to control CO, NO_X, and SO_2 to required emissions limitations (ARM 17.8.752, ARM 17.8.819).

4. Phillips 66 shall utilize 3-stage cyclones, followed by a filter or 4th stage cyclone, to control total filterable particulate emissions from the FCCU catalyst regenerator to required emissions limitations (ARM 17.8.752, ARM 17.8.819).

5. 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).

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

7. All systems within the Phillips 66 refinery and Jupiter sulfur recovery operations (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).

8. The large crude unit heater (H-24), recycle hydrogen heater (H-8401), fractionator feed heater (H-8402), No. 1 H_2 plant reformer heater (H-9401), and No. 2 H_2 Plant Reformer Heater (H-9701) shall be equipped with Ultra Low NO_X Burners (ULNB) (ARM 17.8.752).

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

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

11. Boilers #B-5 and #B-6 shall be equipped with ULNB (ARM 17.8.752, ARM 17.8.819).

12. No. 5 HDS Charge Heater, No. 5 HDS Stabilizer Reboiler Heater, and No.3 Hydrogen Plant Heater shall be equipped with ULNB (ARM 17.8.752, ARM 17.8.819).

13. The separator bays of the two API Separator Tanks shall be covered and sealed and the vapor from these bays shall be routed to a VOC control device to control VOC emissions with at least a 95% control efficiency

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

(ARM 17.8.752). The VOC control device shall be an activated carbon canister (ARM 17.8.49).

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

    a. Phillips 66's collected vapors shall be routed to the Vapor Combustor Unit (VCU) at all times. In the event the VCU was inoperable, Phillips 66 may continue to load only distillates with a Reid vapor pressure of less than 27.6 kilopascals, provided DEQ is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.752).

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

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

16. When a temporary natural gas-fired boiler is necessary, Phillips 66 shall operate the temporary natural gas-fired boiler for no longer than 8 weeks per rolling 12-month period. The temporary boiler shall not exceed a firing rate of 51 MMBtu/hr, and shall only be used during refinery turnarounds (ARM 17.8.749).

17. Phillips 66 shall operate and maintain an amine-based chemical absorption system on the refinery fuel gas system (ARM 17.8.752 and ARM 17.8.819).

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

19. SRU #2 shall be considered subject to 40 CFR 60 Subpart Ja conditions as a modified unit (ARM 17.8.749).

20. SRU #3 shall be equipped with an oxidation tail gas scrubber process (ARM 17.8.752).

21. SRU #1, #2, and #3 shall each be equipped with the following, downstream of the sulfur oxidizers: 2 wet scrubbers in series, followed by 3 parallel vent gas filters (each filter vessel contains four candle filter elements in a nested filter-in-filter design) (ARM 17.8.752 and ARM 17.8.819).

22. The New Cooling Tower installed as part of the 2022 Projects (MAQP 2619-39), Cooling Tower CWT5, and the Cooling Tower CT-615 A/B/C, shall be equipped with high efficiency drift eliminators with a design drift rate not to exceed 0.0010% (ARM 17.8.752). Phillips 66 shall maintain documentation of vendor/manufacturer supplied documentation demonstrating design drift rate, on-site and available upon request (ARM 17.8.749).

C. Emission Limitations

1. Total refinery and sulfur recovery facility emissions shall not exceed the following (ARM 17.8.749, unless otherwise noted):

   a. Jupiter SRU Flare[2]

      i. SO_2 Emissions - 25.00 lbs/hr, 0.30 tons/day.

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

2. Total SO_2 emissions from the Jupiter Main Stack No. 1 plus the Jupiter SRU flare shall not exceed 109.5 TPY (rolling 12-month average) (ARM 17.8.749)

3. Emissions from SRU #1 and SRU #2 combined (Jupiter Main Stack No. 1), shall not exceed the following:

   a. Total filterable particulate: 2.0 lb/hr (ARM 17.8.752, ARM 17.8.749, ARM 17.8.819)

   b. PM_{10} (filterable + condensable): 4.0 lb/hr (ARM 17.8.749)

   c. $PM_{2.5}$ (filterable + condensable): 4.0 lb/hr (ARM 17.8.749)

   d. SO_2: 167 ppmvd (parts per million on a dry, volumetric basis) at 0% O_2 on a 12-hour rolling average basis (ARM 17.8.752, ARM 17.8.819, ARM 17.8.749)

   e. Ammonia: 13.36 lb/hr (ARM 17.8.749)

   f. NO_X: 14.84 lb/hr (ARM 17.8.749, ARM 17.8.752, ARM 17.8.819)

   g. CO: 4.22 lb/hr (ARM 17.8.752, ARM 17.8.819, ARM 17.8.749)

   h. Opacity: 20% averaged over any 6 consecutive minutes (ARM 17.8.304)

4. SRU #3 shall have its own emissions stack, named Jupiter Main Stack No. 2 (ARM 17.8.749). Emissions from Jupiter Main Stack No. 2 shall not exceed:

   a. Total filterable particulate: 2.0 lb/hr (ARM 17.8.752, ARM 17.8.749, ARM 17.8.819)

---

[2] Emissions occur only during times that the ATS plant is not operating and/or during abnormal process condition, process upsets, and/or malfunctions.

b. PM_{10} (filterable + condensable): 4.0 lb/hr (ARM 17.8.749)

c. $PM_{2.5}$ (filterable + condensable): 4.0 lb/hr (ARM 17.8.749)

d. SO_2: 167 ppmvd at 0% O_2 on a 12-hour rolling average basis (ARM 17.8.752, ARM 17.8.749)

e. Ammonia: 13.36 lb/hr (ARM 17.8.749)

f. NO_X: 14.84 lb/hr (ARM 17.8.749, ARM 17.8.752, ARM 17.8.819)

g. CO: 4.22 lb/hr (ARM17.8.752, ARM 17.8.819, ARM 17.8.749)

h. Opacity: 20% averaged over any 6 consecutive minutes (ARM 17.8.304)

5. SRU #1, #2, and #3, combined, shall be limited to (ARM 17.8.749):

a. SO_2: 50 tons per year on a 12-month rolling sum basis.

b. NO_X: 71.50 tons per year on a 12-month rolling sum basis after the Unit 85 Hydrogen Unit starts up. Until then, 65.00 tons per year, determined monthly on a rolling 12-month basis.

c. CO: 18.46 tons per year on a 12-month rolling sum basis.

d. Ammonia: 117.00 tons per year on a 12-month rolling sum basis.

6. <u>FCCU Catalyst Regenerator Stack</u>

a. SO_2 emissions shall not exceed 6.01 lb per thousand barrels of gas oil feed, as determined on a rolling 12-month average basis (ARM 17.8.752, ARM 17.8.819).

b. SO_2 emissions shall not exceed 28.52 tons per year as determined monthly on a rolling 12-month sum basis (ARM 17.8.749).

c. 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. SO_2 emission data during startup, shutdown or malfunction of the FCCU or during periods of malfunction of a control system or pollutant reducing catalyst additive system will not be used in determining compliance with the 7-day SO_2 emission limit, provided that Phillips 66 implements good air pollution control practices to minimize SO_2 emissions. The 7-day SO_2 emission limit shall not apply during periods of hydrotreater outages provided that Phillips 66 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 Hydrotreater Outage Plan (Plan). In those instances where Phillips 66 chooses (as allowed by the Plan provisions) to exclude the

Hydrotreater Outage period from the 7-day SO_2 emission limit, it must demonstrate compliance with the applicable requirements of the Plan in the post-outage report required pursuant to the Plan. 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 American Society of Mechanical Engineers (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 days in which the FCCU is not operating, no SO_2 value shall be used in the average, and those periods shall be skipped in determining the 7-day and 365-day averages (ARM 17.8.749).

d. SO_2 emissions from FCCU shall not exceed 9.8 kilograms per Megagram (kg/Mg, or 20 lb/ton) coke burnoff on a 7-day rolling average basis, in accordance with 40 CFR 60.104(b)(2) and (c).

   As an alternative, Phillips 66 shall process in the FCCU fresh feed that has a total sulfur content no greater than 0.30 percent by weight on a 7-day rolling average basis, in accordance with 40 CFR 60.104(b)(3) and (c). This limit became effective on February 1, 2005 (ARM 17.8.749).

e. CO emissions shall not exceed 150 ppmvd at 0% O_2 based on a rolling 365-day average basis, including periods of startup and shutdown (ARM 17.8.749, ARM 17.8.752, ARM 17.8.819).

f. CO emissions 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 Phillips 66 implements good air pollution control practices to minimize CO emissions (ARM 17.8.749, ARM 17.8.752, ARM 17.8.819).

g. CO emissions shall not exceed 144.96 tons per year on a rolling 12-month sum basis (ARM 17.8.749).

h. 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. NO_X emission data during startup, shutdown, or malfunction of the FCCU or during periods of malfunction of a control system or pollutant reducing catalyst additive system will not be used in determining compliance with the 7-day NO_x emission limit, provided that Phillips 66 implements good air pollution control practices to minimize NO_X emissions. The 7-day NO_X emission limit shall not apply during periods of hydrotreater outages provided that Phillips 66 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 Hydrotreater Outage Plan. In those instances where Phillips 66 chooses (as allowed per the Plan provisions) to exclude the Hydrotreater

Outage period from the 7-day NO_X emission limit, it must demonstrate compliance with the applicable requirements of the Plan in the post-outage report required pursuant to the Plan. 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 days in which the FCCU is not operating, no NO_x value shall be used in the average, and those periods shall be skipped in determining the 7-day and 365-day averages (ARM 17.8.749, ARM 17.8.752, ARM 17.8.819).

i. NO_X emissions shall not exceed 78.10 tons per year on a rolling 12-month sum basis (ARM 17.8.749).

j. Total filterable particulate emissions - The FCCU shall not exceed the limit of 1.0 lb/1000 lbs coke burned (ARM 17.8.749, ARM 17.8.752, ARM 17.8.819).

k. PM_{10} and $PM_{2.5}$ emissions, including condensable emissions, from the FCCU shall not exceed 51.29 tons per year on a rolling 12-month sum basis (ARM 17.8.749).

l. Opacity - not to exceed 30%, except for one 6-minute average in any 1 hour period (ARM 17.8.749).

m. Phillips 66 shall limit throughput of gas oil to the FCCU to 9,490,000 bbl/yr as determined on a rolling 12-month average basis (ARM 17.8.749 and ARM 17.8.1211).

7. <u>Refinery Fuel Gas Heaters/Furnaces</u>

a. Phillips 66 shall not burn fuel oil in any of its heaters (ARM 17.8.749).

b. Phillips 66 shall not burn in any refinery fuel gas combustion devices any fuel that contains H_2S in excess of 162 ppmv determined hourly on a 3 hour rolling average basis and 50 ppmv determined daily on a 365 successive calendar day rolling average basis (ARM 17.8.752, ARM 17.8.749).

c. The PSA purge gas used as heater fuel in the No. 1 H_2 Plant Reformer Heater (H-9401), and the No. 2 H_2 Plant Reformer Heater (H-9701) shall be sulfur free (ARM 17.8.752).

d. The No. 1 H_2 Unit Reformer Heater (H-9401) and No. 2 H_2 Unit Reformer Heater (H-9701) shall burn only natural gas, PSA off-gas, and/or cryo off-gas, which are inherently low sulfur fuels (ARM 17.8.749).

e. The H-2, H-4, H-5, H-15, and H-19 heaters shall be made inoperable and/or removed from the site (ARM 17.8.749).

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

i. Emission Point 2, H-1;
ii. Emission Point 7, H-10 – No. 2 HDS;
iii. Emission Point 8, H-11 – No. 2 HDS Debutanizer Reboiler;
iv. Emission Point 9, H-12 – No. 2 HDS Main Frac. Reboiler;
v. Emission Point 10, H-13 – Catalytic Reforming
vi. Unit #2;
vii. Emission Point 11, H-14 – Catalytic Reforming
viii. Unit #2;
ix. Emission Point 13, H-16 – Saturated Gas Stabilizer Reboiler and PB Merox Disulfide Offgas;
x. Emission Point 14, H-17;
xi. Emission Point 15, H-18;
xii. Emission Point 17, H-20;
xiii. Emission Point 18, H-21;
xiv. Emission Point 20, H-23 – Catalytic Reforming Unit #2;
xv. Emission Point 21, H-24;
xvi. Emission Point 6, H-3901 – Coker Heater;
xvii. Emission Point 28, H-8401 – Recycle Hydrogen Heater;
xviii. Emission Point 29, H-8402 – Fractionator Feed Heater.

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

h. Opacity from each of the Refinery Fuel Gas Heaters/Furnaces constructed after 1968, including the No. 5 HDS Charge Heater (H-9501), No. 5 HDS Stabilizer Reboiler Heater (H-9502), No. 2 H_2 Plant Reformer Heater (H-9701), Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and the No. 1 H_2 Plant Reformer Heater (H-9401) shall each not exceed 20% averaged over 6 consecutive minutes (ARM 17.8.304).

i. Emissions from the Small Crude Unit Heater (H-1) (ARM 17.8.752), Large Crude Unit Heater (H-24) (ARM 17.8.752), and Vaccum Furance (H-17) (ARM 17.8.749), shall not exhibit an opacity of 10% or greater averaged over 6 consecutive minutes.

j. PM_{10} emissions, including condensable emissions, from the Coker Furnace H-3901, No. 4 HDS Recycle Hydrogen Heater H-8401, No. 4 HDS Fractionator Feed Heater H-8402, No. 5 HDS Charge Heater H-9501, No. 5 HDS Stabilizer Heater H-9502, Catalytic Reforming Unit #2 H-13, Catalytic Reforming Unit #2 H-14, Saturated Gas

Stabilizer Reboiler H-16, Catalytic Reforming Unit #2 H-23, Alkyl Heater H-21, and the FCCU Preheater H-18, shall not exceed 0.0031 pounds per million british thermal units (lb/MMBtu) on a higher heating value (HHV) basis (ARM 17.8.749).

k. $PM_{2.5}$ emissions, including condensable emissions, from the Coker Furnace H-3901, No. 4 HDS Recycle Hydrogen Heater H-8401, No. 4 HDS Fractionator Feed Heater H-8402, No. 5 HDS Charge Heater H-9501, No. 5 HDS Stabilizer Heater H-9502, Catalytic Reforming Unit #2 H-13, Catalytic Reforming Unit #2 H-14, Saturated Gas Stabilizer Reboiler H-16, Catalytic Reforming Unit #2 H-23, and the Alkyl Heater H-21, FCCU Preheater H-18shall not exceed 0.0021 lb/MMBtu on a HHV basis (ARM 17.8.749).

l. NO_X emissions from the Coker Heater H-3901, No. 4 HDS Recycle Hydrogen Heater H-8401, No. 4 HDS Fractionator Feed Heater H-8402, and No. 1 H_2 Plant Reformer Heater H-9401, combined, shall not exceed 17.22 lb/hr and 75.44 TPY on a rolling, 12 month sum basis (ARM 17.8.749).

m. Emissions from the Small Crude Unit Heater (H-1) shall not exceed:

   i. NO_X: 0.030 lb/MMBtu on a HHV basis. The averaging period intended for this condition is an averaging period as would be utilized in an approved source test protocol accepted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.749).

n. Emissions from the Large Crude Unit Heater (H-24) shall not exceed:

   i. NO_X: 40 ppmvd at 0% O_2 on a 30-day rolling average basis, determined daily (ARM 17.8.749, ARM 17.8.752, ARM 17.8.340, and 40 CFR 60 Subpart Ja).

o. Emissions from the Vacuum Furnace (H-17) shall not exceed:

   i. NO_X: 30 ppmvd at 0% O_2 on a 30-day rolling average basis, determined daily (ARM 17.8.752).

p. Emissions from the No. 1 H_2 Unit Reformer Heater (H-9401) shall not exceed:

   i. NO_X: 0.042 lb/MMBtu on a HHV basis. The averaging period intended for this condition is an averging period as would be utilized in an approved source test protocol accepted in accord with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.749).

   ii. CO: 0.025 lb/MMBtu (ARM 17.8.752).

iii. PM_{10} and $PM_{2.5}$: 0.0075 lb/MMBtu (ARM 17.8.752 and ARM 17.8.819).

q. Emissions from the No. 5 HDS Charge Heater (H-9501) shall not exceed:

i. NO_X: 0.03 pounds per million British thermal units (lb/MMBtu) on a HHV basis (ARM 17.8.749, ARM 17.8.752).

ii. CO: 0.317 lb/MMBtu on a HHV basis when the heater is operating at 10.9 MMBtu/hr or less (ARM 17.8.749, ARM 17.8.752).

iii. CO: 0.1585 lb/MMBtu on a HHV basis when the heater is operating at greater than 10.9 MMBtu/hr (ARM 17.8.749, ARM 17.8.752).

r. Emissions from the No. 5 HDS Stabilizer Reboiler Heater (H-9502) shall not exceed:

i. NO_X: 0.03 lb/MMBtu on a HHV basis (ARM 17.8.749, ARM 17.8.752).

ii. CO: 0.1585 lb/MMBtu on a HHV basis when the heater is operating at 29.9 MMBtu/hr or less (ARM 17.8.749, ARM 17.8.752).

iii. CO: 0.091 lb/MMBtu when the heater is operating at greater than 29.9 MMBtu/hr (ARM 17.8.749, ARM 17.8.752).

s. Emissions from the No. 2 H_2 Plant Reformer Heater (H-9701) shall not exceed:

i. NO_X: 0.03 lb/MMBtu (ARM 17.8.749, ARM 17.8.752 and ARM 17.8.819).

ii. CO: 0.025 lb/MMBtu (ARM 17.8.749, ARM 17.8.752).

iii. PM_{10} and $PM_{2.5}$: 0.0075 lb/MMBtu (ARM 17.8.752 and ARM 17.8.819).

t. NO_X emissions from the Coker Heater (H-3901) shall not exceed 0.04 lb/MMBtu on a HHV basis (ARM 17.8.749).

u. NO_X emissions from the Recycle Hydrogen Heater (H-8401) shall not exceed 0.03 lb/MMBtu on a lower heating value (LHV) basis (ARM 17.8.752).

v. NO_X emissions from the Fractionator Feed Heater (H-8402) shall not exceed 0.03 lb/MMBtu on a lower heating value (LHV) basis (ARM 17.8.752).

8. Main Boilerhouse Stack

a. SO_2 Emissions shall not exceed: 321.4 lbs/hr, rolling 24-hour average; 3.857 ton/day; 1,407.8 TPY (fuel oil and fuel gas combustion) (ARM 17.8.749).

b. SO_2 Emissions shall not exceed: 300 TPY from fuel oil combustion, based on a rolling 365-day average as determined by the existing SO_2 Continuous Emissions Monitoring System (CEMS) or replacement SO_2 CEMS subsequently installed and certified (ARM 17.8.749).

c. H_2S content of fuel gas burned shall not exceed 0.10 gr/dscf, rolling 3-hr average (ARM 17.8.749)

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

e. Opacity - 40% averaged over any 6 consecutive minutes, except during times that the exhaust from only boilers #B-5 and #B-6 are being routed to the main boiler stack, the opacity limit is 20% (ARM 17.8.304).

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

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

h. 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).

9. Sulfur Pits of Sulfur Recovery Plant

Phillips 66 shall capture and treat or incinerate emissions from its sulfur pits with the other emissions from its sulfur recovery plant. Emissions sent to the incinerator are measured as part of the total emissions exiting the Jupiter Main Stack No. 1 (ARM 17.8.749).

10. Total SO_2 emissions for refinery and sulfur recovery facilities

Total SO_2 emissions for refinery and sulfur recovery facilities shall not exceed the limit of 3,103 TPY. In addition, where applicable, all other federal emission limitations shall be met (ARM 17.8.749).

11. All access roads shall use either paving or chemical dust suppression as appropriate to limit excessive fugitive dust, with water as a back-up measure, to maintain compliance with ARM 17.8.308 and the 20% opacity limitation. Phillips 66 shall use reasonable precautions during construction, and earth-moving activities shall use reasonable precautions to limit excessive fugitive dust and to mitigate impacts to nearby residential and commercial places (ARM 17.8.749, ARM 17.8.308).

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

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

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

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

    d. Phillips 66 shall not cause or authorize to be discharged into the atmosphere from the enclosed VCU:

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

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

13. Refinery Main Plant Relief Flare Stack

    a. The Main Refinery Plant Flare shall not burn any fuel gas that contains H_2S in excess of 162 ppm determined hourly on a 3-hour rolling average basis. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja).

14. Jupiter Flare

    a. The Jupiter Flare shall not burn any fuel gas that contains H_2S in excess of 162 ppm determined hourly on a 3-hour rolling average basis. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja).

15. The maximum conductivity of water in the New Cooling Tower installed as part of MAQP 2619-39, the Vacuum Unit Cooling Tower CWT5, as well as the Jupiter Cooling Tower CT-615 A/B/C, shall not exceed 3,130 microsiemens per centimeter (μS/cm) at 25 degrees Celcius (ARM 17.8.749).

16. <u>Backup Coke Crusher and Associated Diesel Fired Engine (CG3810)</u>

    a. The Coke Crusher and the Backup Coke Crusher shall not be operated simultaneously (ARM 17.8.749).

    b. The engine associated with CG3810 shall not exceed a horsepower rating of 300 hp and shall have an EPA certification of Tier 3 or higher (ARM 17.8.749).

    c. Phillips 66 shall use only ultra-low-sulfur diesel fuel with a sulfur content less than or equal to 0.0015% in the engine associated with CG3810 (ARM 17.8.752).

17. <u>Misc Diesel Engines</u>

    a. The Backup Firepump Engine capacity shall not exceed 665 hp and shall have an EPA certification of Tier 3 or higher (ARM 17.8.749).

    b. The Emergency Generator Engine (G-8401) for the HDS Flare Drum Pumps shall not have a capacity exceeding 300 hp and shall have an EPA cerfication of Tier 3 or higher (ARM 17.8.749).

    c. The Emergency Generator Engine (G-8401) for the HDS Flare Drum Pumps shall not exceed 1,000 hours of operation in any rolling 12-month period (ARM 17.8.749).

18. <u>Vacuum Furnace (H-17) and Large Crude Unit Heater (H-24)</u>

    a. The total NO_x emissions from the Vacuum Furnace (H-17) and Large Crude Unit Heater (H-24) shall not exceed 29.8 tons per rolling 12-month period. (ARM 17.8.749)

    b. The toal SO_2 emissions from the Vacuum Furnace (H-17) and Large Crude Unit Heater (H-24) shall not exceed 7.4 tons per rolling 12-month period (ARM 17.8.749).

D. Testing Requirements – NSPS, NESHAP, and MACT

1. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60 Subpart Db,

Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.

2. Phillips 66 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.

3. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60 Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.

4. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60 Subpart Ka, Standards of Performance for Storage Vessels for Petroleum Liquids. This shall apply to all petroleum liquid storage vessels for which construction, reconstruction or modification commenced after May 18, 1978, and prior to July 23, 1984 (for requirements not overridden by 40 CFR 63 Subpart CC). These requirements shall be as specified in 40 CFR 60.110a through 60.115a.

5. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60 Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels. This shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984 (for requirements not overridden by 40 CFR 63 Subpart CC).

6. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60 Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006.

7. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60 Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.

8. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60 Subpart QQQ, Standards of Performance for Volatile Organic Compound Emissions from Petroleum Refinery Wastewater Systems (for requirements not overridden by 40 CFR 63 Subpart CC).

9. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63 Subpart R, NESHAPs for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations).

10. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63 Subpart CC, NESHAPs from Petroleum Refineries.

11. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63 Subpart UUU, NESHAPs for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

12. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63 Subpart DDDDD, NESHAPS for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

13. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63 Subpart EEEE, NESHAPs for Organic Liquids Distribution (Non-Gasoline).

14. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63 Subpart WW, National Emissions Standards for Storage Vessels (Tanks) – Control Level 2.

E. Emission Testing and Monitoring

1. Phillips 66 shall monitor the FCCU Catalyst Regenerator for compliance with PM_{10} and $PM_{2.5}$ emissions limits (including condensables) in the following manner (ARM 17.8.749 and ARM 17.8.105):

   a. By the startup of the FCCU following the planned refinery turnaround in which physical modifications of the FCCU as permitted in MAQP #2619-39 is accomplished, Phillips 66 shall have installed a sampling port as necessary for Method 201a and Method 202 testing.

   b. Within 180 days of startup of the FCCU following the planned refinery turnaround in which physical modifications of the FCCU as permitted in MAQP #2619-39 is accomplished, Phillips 66 shall conduct a Method 201a and Method 202 test. Due to velocity of the stack, it may be found that a Method 201a cannot be completed within the requirements of the Method. Phillips 66 shall demonstrate a good faith effort to complete a successful test. Should velocity of the stack pose issues such that Method 201a cannot be accomplished within the requirements of the method, Phillips 66 shall prepare a detailed report detailing why the test cannot be completed, detailed explanation of the efforts made to complete a successful test, and provide the results of the Method 201a and 202 testing. A minimum of three full runs shall be completed regardless of Method 201a invalidations occurring.

   c. If a Method 201a cannot be successfully completed, Phillips 66 shall institute the FCCU Catalyst Regenerator Alternative Monitoring Compliance Demonstration Method for PM_{10} and $PM_{2.5}$ (including condensables), as follows:

i. Within 30 days of determination of a need for the alternative compliance demonstration methodology, Phillips 66 shall propose a detailed filterable particulate size distribution study to DEQ. The submitted study shall include stack test protocol for Method 5 with a Method 202 back-half, and shall be conducted under catalyst conditions (catalyst type, catalyst emissions control additives, and catalyst refresh rates) which are representative of normal operations. Each operational scenario (each control technology operation scenario to be used) shall be tested separately.

ii. Within 90 days of determination of the need for an alternative compliance demonstration methodology, Phillips 66 shall conduct the Method 5 with Method 202 back-half test.

iii. Within 60 days of conducting the particle size distribution study, Phillips 66 shall report the results to DEQ. The results shall include the Method 5 and Method 202 results, the size distribution determinations, and the results of applying the size distribution determinations to the Method 5 plus Method 202 results, such that PM_{10} (including condensables) and $PM_{2.5}$ (including condensables) are reported.

iv. Compliance with the FCCU PM_{10} and $PM_{2.5}$ emission limits will be determined based on the reported results of applying the particle size distribution to the Method 5 results, plus the Method 202 results.

v. The particle size distribution study shall be repeated at least every 5 years, or as may be requested by Phillips 66 or DEQ.

vi. The Method 5 with Method 202 testing shall be conducted annually.

vii. Reporting of Method 5 with particle size distribution applied, plus Method 202, shall be reported with the source test reports.

d. Annually thereafter the 180 day test, Phillips 66 shall conduct a Method 201a and Method 202 test, or, if such testing is previously demonstrated as not achievable within the requirements of the Method, in accord with the FCCU Catalyst Regenerator Alternative Monitoring Compliance Demonstration Method for PM_{10} and $PM_{2.5}$. Phillips 66 may reattempt a Method 201a at any time.

2. Phillips 66 shall test boilers #B-5 and #B-6 for NO_X and CO compliance, both pollutants concurrently, on an every 5-year basis or according to another testing/monitoring schedule as may be approved by DEQ (ARM 17.8.105 and 17.8.749).

3. The bulk loading rack VCU shall be tested for compliance with the total organic compounds limitation every 5 years. Phillips 66 shall conduct the test methods and procedures as specified in 40 CFR 63.425, Subpart R (ARM 17.8.105 and 17.8.342).

4. Phillips 66 shall perform a Method 5 test on the FCCU catalyst regenerator stack at least once per calendar year to monitor compliance with the FCCU total filterable PM limitation. The annual tests shall be scheduled no closer than 6 months apart. (ARM 17.8.749).

5. Phillips 66 shall, within 180 days of completion of the Coker Unit changes, test the Coker Heater H-3901 for NO_X and CO concurrently to determine emissions on a lb/MMBtu basis. Thereafter, the Coker Heater shall be tested for NO_X and CO on an every calendar year schedule, with no two tests closer than 180 days apart (ARM 17.8.749 and ARM 17.8.105). Results of the tests shall be used as the emissions factors in determining mass emissions rates on a rolling 12-month basis (ARM 17.8.749). Phillips 66 may request a discontinuaunce of this testing requirement after three successive tests demonstrating compliance. Such request, and DEQ's determination, shall be made in writing. (ARM 17.8.749).

6. Phillips 66 shall test the H-8401, H-8402, and H-9401 to determine NO_X emissions on a lb/MMBtu basis once every 5 calendar years (ARM 17.8.749 and ARM 17.8.105). Results of the tests shall also be used as the emissions factors in determining mass emissions rates on a rolling 12-month sum basis (ARM 17.8.749).

7. Phillips 66 shall, within 180 days of startup of each SRU modified as permitted in MAQP #2619-39, test the associated Jupiter Main Stack for total filterable PM, PM_{10} (including condensables), $PM_{2.5}$ (including condensables), NO_X, and CO. For purposes of this testing, operations representative of near maximum capacity under operating scenario(s) producing the highest emissions of each pollutant, shall be required. Testing of Main Stack No. 1 shall occur with SRU I and SRU II operating at or near capacity. Testing of Main Stack No. 2 shall occur with SRU III operating at or near capacity. Such testing shall continue on an every 3 year basis. (ARM 17.8.749 and ARM 17.8.105).

8. Phillips 66 shall install and operate the following CEMS/continuous emission rate monitors (CERMs):

   a. <u>Jupiter Main Stack No. 1 and Main Stack No. 2</u>

      i. SO_2 (SO_2 Board Ordered Stipulations as submitted in the State Implementation Plan (STIP), 40 CFR 60 Subpart Ja, ARM 17.8.749)

      ii. O_2 (40 CFR 60 Subpart Ja)

iii. Volumetric flow rate (SO_2 STIP)

b. <u>FCCU Stack</u>

i. SO_2 (40 CFR 60 Subpart J and ARM 17.8.749)

ii. Volumetric flow rate (SO_2 STIP)

iii. Opacity (40 CFR 60 Subpart J and ARM 17.8.749)

iv. CO (40 CFR 60 Subpart J and ARM 17.8.749)

v. NO_x (ARM 17.8.749)

vi. O_2 (ARM 17.8.749)

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

i. SO_2 (SO_2 STIP; ARM 17.8.749)

ii. Volumetric flow rate (SO_2 STIP)

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

i. NO_X (40 CFR 60 Subpart Db)

ii. O_2 (ARM 17.8.749)

e. <u>Vacuum Furnace H-17 and Large Crude Unit Heater H-24</u>

i. NO_X for NSPS Ja and BACT limitations on a ppmvd basis. CEMS equipment, operation, calibration, performance evaluation, and emissions recording shall be accomplished utilizing the methodologies described and referenced in 40 CFR 60 Subpart Ja, including 40 CFR 60 Subpart A and Appendix F and shall include O_2 monitoring (ARM 17.8.749, ARM 17.8.340, 40 CFR 60 Subpart Ja).

f. <u>Refinery Main Plant Relief Flare:</u>

i. H_2S or TRS (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja)

ii. Flow (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja)

iii. Phillips 66 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, Phillips 66 shall also measure or estimate (as appropriate) all SO_2 emissions which result from gases being directed to and combusted in the flare (ARM 17.8.749)

iv. 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 17.8.749)

v. Recordkeeping requirements (see Sections II.F.1-2) (ARM 17.8.749)

g. Jupiter Flare

i. Flow (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja)

ii. Jupiter Sulphur shall maintain records of the duration of all periods in which the rupture disk has been breached. During such periods, Jupiter Sulphur shall also measure or estimate (as appropriate) all SO_2 emissions which result from gases being directed to and combusted in the flare (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja)

iii. 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 17.8.749)

iv. Recordkeeping requirements (see Sections II.F.1-2) (ARM 17.8.749)

9. Enforcement of requirements, where applicable, shall be determined by utilizing data taken from CEMS and other DEQ-approved sampling methods. However, opacity compliance may also be determined via EPA Reference Method 9 by a certified observer or monitor (ARM 17.8.749).

a. The above does not relieve Phillips 66 from meeting any applicable requirements of 40 CFR 60 Appendices A and B, or other stack testing that may be required by DEQ.

b. Other stack testing may include, but is not limited to, the following air pollutants: SO_2; NO_X; ammonia (NH_3); CO; PM, PM_{10}, $PM_{2.5}$, including condensable emissions; and VOC.

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

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

10. Phillips 66 shall install, operate and maintain the applicable STIP/SO_2 Control Plan required CEMS on the Jupiter Main Stack 1 (SO_2, O_2 and volumetric flowrate), the FCCU Stack (volumetric flow rate), and the Main Boiler Stack (SO_2 and volumetric flow rate). Emission monitoring shall be subject to 40 CFR 60 Subpart J or Ja as applicable, Appendix B (Performance Specifications 1, 2, 3, 4/4A/4B, and 6) and Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.749).

11. Phillips 66 shall install, operate and maintain applicable CEMS as originally required by federal consent decree on the FCCU (SO_2, opacity, CO, NO_X, and O_2). Emission monitoring shall be subject to 40 CFR 60 §60.11, 60.13 and Part 60, Appendix A, Appendix B (Performance Specifications 2 and 3 and Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.749). With respect to Appendix F, in lieu of the requirements of 40 CFR 60 Appendix F 5.1.1, 5.1.3 and 5.1.4, Phillips 66 shall conduct either a Relative Accuracy Audit or a Relative Accuracy Test Audit once every twelve (12) calendar quarters, provided that a Cylinder Gas Audit is conducted each calendar quarter.

12. Phillips 66 shall install, operate and maintain the applicable NO_X and O_2 CEMS/CERMS on Boilers B-5 and B-6. Emission monitoring shall be subject to 40 CFR 60 Subpart Db; Appendix B (Performance Specifications 2, 3, 4/4A/4B, and 6). Emission monitoring shall be subject to 40 CFR 60, Appendix F or an alternate site-specific monitoring plan approved by DEQ, as appropriate (ARM 17.8.749).

13. All CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, Phillips 66 shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated. The DEQ shall approve such contingency plans (ARM 17.8.749).

14. Compliance testing and continuous monitor certification shall be as specified in 40 CFR 60, Appendices A and B. Test methods and procedures, where there is more than one option for any given pollutant, shall be worked out with DEQ prior to commencement of testing (ARM 17.8.749).

15. Phillips 66 shall conduct compliance testing and continuous monitor certification as specified in 40 CFR 60 Appendices A and B, within 180 days of initial start up of the affected facility (ARM 17.8.749).

16. Any stack testing requirements that may be required shall be conducted according to 40 CFR 60 Appendix A and ARM 17.8.105, Testing Requirements provisions (ARM 17.8.749).

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

18. The DEQ may require further testing (ARM 17.8.105).

F. Recordkeeping and Reporting

1. Phillips 66 shall provide quarterly and/or semi-annual emission reports from all emission rate monitors. In addition to any specific NSPS or NESHAP reporting requirements, the periodic reports shall include the following (ARM 17.8.749):

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

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

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

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

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

   Phillips 66 shall submit the quarterly and/or semi-annual emission reports within 30 days of the end of each reporting period.

2. Phillips 66 shall keep DEQ 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):

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

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

   d. Monitoring data shall be maintained for a minimum of 5 years at the Phillips 66 Refinery and Jupiter sulfur recovery facilities.

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

3. Phillips 66 shall report to DEQ any time in which the sour water stripper stream from the refinery is diverted away from the sulfur recovery facility. Said excess emission reports shall include the period of diversion, estimate of lost raw materials (H_2S and NH_3), and resultant pollutant emissions, including circumstances explaining the diversion of this stream. Said excess emission reports shall discuss what corrective actions will be taken to prevent recurrences of the situation and what caused the upset. These reports shall address, at a minimum, the requirements of ARM 17.8.110 (ARM 17.8.749).

4. Phillips 66 shall document, by month, the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No. 2 H_2 Plant PSA Offgas Vent. By the 30th day of each month Phillips 66 shall total the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No. 2 H_2 Plant PSA Offgas Vent during the previous month. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

5. Phillips 66 shall document, by month, the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No. 1 H_2 Plant PSA Offgas Vent. By the 30th day of each month Phillips 66 shall total the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No. 1 H_2 Plant PSA Offgas Vent during the previous month. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

6. Phillips 66 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 STIP emissions and CEMS/CERMS reporting periods (ARM 17.8.749).

7. Phillips 66 shall document, annually, the number of bbl/yr of gas oil throughput as determined on a rolling 12-month average basis from the FCCU (ARM 17.8.749 and ARM 17.8.1212).

8. Phillips 66 shall document, annually, the number of operational hours of the Backup Coke Crusher. The information shall be submitted along with the annual emission inventory (ARM 17.8.749).

9. Phillips 66 shall document, annually, the maximum sulfur content of the diesel fuel used by the engine associated with CG3810 for the previous calendar year. Vendor specifications or certification that the fuels met the maximum sulfur content allowed by the current motor fuel regulations (40 CFR Part 80) will satisfy this requirement. The information shall be submitted along with the annual emission inventory (ARM 17.8.749).

10. Phillips 66 shall document, by the 25th day of each month, the monthly and rolling 12 month total of hours of operation of the Emergency Generator Engine (G-8401) for the HDS Flare Drum Pumps for the previous month. The information shall be submitted along with the annual emissions inventory (ARM 17.8.749).

11. Phillips 66 shall document, by the 25th day of each month, the monthly and rolling 12-month total NO_X emissions from the H-3901, H-8401, H-8402, and the H-9401. The information shall be submitted semiannually (i.e. in the Title V semi-annual monitoring reports) (ARM 17.8.749).

12. Phillips 66 shall document, by the 25th day of each month, the monthly and rolling 12-month total combined SO_2 emissions from the SRUs. The information shall be submitted semiannually (i.e. in the Title V semi-annual monitoring reports) (ARM 17.8.749).

13. Phillips 66 shall develop and document emissions factors for each SRU based on source testing of representative operational scenarios, such that each operational scenario has an associated emissions factor, except for ammonia, for which emissions may be estimated based on mass balance. By the 25th day of each month, the NO_X, SO_2, total filterable particulate, PM_{10} (including condensibles), and $PM_{2.5}$ (including condensibles) monthly and rolling 12 month totals shall be documented. The information shall be submitted semiannually (i.e. in the Title V semi-annual monitoring reports). Until emissions factors are developed based on source testing, emissions factors as presented in the application for MAQP #2619-39 shall be used (ARM 17.8.749).

14. Phillips 66 shall test a representative grab sample of cooling tower water for each cooling tower at least once per calendar quarter. Method 120.1 conductivity test procedures, as found for use under 40 CFR 136, or another equivalent method as may be approved by DEQ, shall be utilized. Phillips 66 has been approved by DEQ to utilize EPA Method 2510B to determine conductivity. Phillips 66 shall maintain records of sample date and results. Such information shall be submitted semiannually (i.e. in the Title V semi-annual monitoring reports) (ARM 17.8.749).

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

1. Phillips 66 shall keep records and furnish reports to DEQ as required by 40 CFR 60 Subpart Kb, for requirements not overridden by 40 CFR 63 Subpart CC. These reports shall include information described in 40 CFR 60.115b. If Phillips 66 chooses to comply with 40 CFR 63 Subpart WW to satisfy the requirements of 40 CFR 60.112b through 60.117b, Phillips 66 shall keep and furnish records according to 40 CFR 63.1065, 40 CFR 63.1066, and 40 CFR 60.110b(e)(5), as applicable (ARM 17.8.749).

2. Phillips 66 shall provide copies to DEQ, upon DEQ's request, of any records of tank testing results required by 40 CFR 60.113b and monitoring of operations required by 40 CFR 60.116b. Records shall be available according

to the time period requirements as described in 40 CFR 60.115b and 40 CFR 60.116b. If Phillips 66 chooses to comply with 40 CFR 63 Subpart WW to satisfy the requirements of 40 CFR 60.112b through 60.117b, Phillips 66 shall comply with the requirements of 40 CFR 63.1063, 40 CFR 63.1065, and 40 CFR 63.1066, as applicable (ARM 17.8.749).

3. Phillips 66 shall keep records and furnish reports to DEQ as required by 40 CFR 60 Subpart QQQ, for requirements not overridden by 40 CFR 63 Subpart CC (ARM 17.8.749).

4. Phillips 66 shall provide copies to DEQ, upon DEQ's request, of any records of testing results, monitoring operations, recordkeeping and report results as specified under 40 CFR 60 Subpart QQQ, Sections 60.693-2, 60.696, 60.697, and 60.698, for requirements not overridden by 40 CFR 63 Subpart CC (ARM 17.8.749).

5. Phillips 66 shall supply DEQ's Permitting and Compliance Division with the reports as required by 40 CFR 61 Subpart FF, NESHAP for Benzene Waste Operations, for requirements not overridden by 40 CFR 63 Subpart CC (ARM 17.8.749).

6. Phillips 66 shall keep all records and furnish all reports to DEQ as required by 40 CFR 63 Subpart R, NESHAPs for Gasoline Distribution Facilities. These reports shall include information described in 40 CFR 63.424, 63.427, and 63.428 (ARM 17.8.749).

7. Phillips 66 shall keep all records and furnish all reports to DEQ as required by 40 CFR 63 Subpart CC, NESHAPs for Petroleum Refineries (MACT I). For storage vessels, Phillips 66 shall keep all records and furnish all reports to DEQ as required by 40 CFR 63 Subpart CC, NESHAPs for Petroleum Refineries (MACT I), 40 CFR 60 Subpart Kb, or 40 CFR 63 Subpart WW, as applicable (ARM 17.8.749).

8. Phillips 66 shall keep all records and furnish all reports to DEQ as required by 40 CFR 63 Subpart UUU, NESHAPs for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (MACT II) (ARM 17.8.749).

9. Phillips 66 shall keep all records and furnish all reports to DEQ as required by 40 CFR 63 Subpart EEEE, NESHAPs for Organic Liquids Distribution (Non-Gasoline) (ARM 17.8.749).

H. Operational Reporting Requirements

1. Phillips 66 shall supply DEQ with annual production information for all emission points, as required by DEQ in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the most recent emission inventory report and sources identified in this permit.

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

Point Name	**Segment**	**Throughput Variable**
Boiler #1	Fuel Gas	MMBtu
Boiler #2	Fuel Gas	MMBtu
Boiler #5	Fuel Gas	MMBtu
Boiler #6	Fuel Gas	MMBtu
Temporary Boiler	Natural Gas	MMBtu
H-1: Small Crude Heater	Fuel Gas	MMBtu
H-3: FCCU - Peabody Heater	Fuel Gas	MMBtu
H-10: HDS #2 Charge Heater	Fuel Gas	MMBtu
H-11: HDS #2 Debutanizer Reboiler	Fuel Gas	MMBtu
H-12: HDS #2 Main Frac Reboiler	Fuel Gas	MMBtu
H-13: Reformer #2 - #2 Reactor Preheater	Fuel Gas	MMBtu
H-14: Reformer #2 - #3 Reactor Preheater	Fuel Gas	MMBtu
H-16: Sat Gas Plant Heater	Fuel Gas	MMBtu
H-17: Vacuum Heater	Fuel Gas	MMBtu
H-18: FCC Pre-Heater	Fuel Gas	MMBtu
H-20: Butamer/Feed Prep Heater	Fuel Gas	MMBtu
H-21: Alky Heater	Fuel Gas	MMBtu
H-23: Reformer #2 - #1 Reactor Preheater	Fuel Gas	MMBtu
H-24: Large Crude Heater	Fuel Gas	MMBtu
H-3901: Coker Heater	Fuel Gas	MMBtu
H-8401: HDS #4 Recycle Hydrogen Heater	Fuel Gas	MMBtu
H-8402: HDS #4 Fractionation Feed Heater	Fuel Gas	MMBtu
H-9401: Hydrogen #1 Heater	Natural Gas	MMBtu
	PSA Gas	MMBtu
	Cryo Gas	MMBtu
H-9501: HDS #5 Recycle Gas Heater	Fuel Gas	MMBtu
H-9502: HDS Stabilizer Reboiler Heater	Fuel Gas	MMBtu
H-9701: No. 2 H_2 Plant Reformer Heater	Natural Gas	MMBtu
	PSA Gas	MMBtu
	Cryo Gas	MMBtu
Refinery Flare	Flare Gas	MMBtu
Jupiter Flare	Flare Gas	MMBtu

Point Name	Segment	Throughput Variable
SRU #1	lb emissions /yr (by pollutant)	1 (yr)
SRU #2	lb emissions/yr (by pollutant)	1 (yr)
SRU #3	lb emissions/yr (by pollutant)	1 (yr)
FCCU	barrels throughput	1000 barrels
New Cooling Tower 2022	Water Throughput	MM Gal
Cooling Tower Combination Unit	Water Throughput	MM Gal
Cooling Tower Condensate Unit	Water Throughput	MM Gal
Cooling Tower Vacuum Unit	Water Throughput	MM Gal
Cooling Tower CT 615 A/B/C	Water Throughput	MM Gal
Cooling Tower CT 120	Water Throughput	MM Gal
Cooling Tower CT 602	Water Throughput	MM Gal
Wastewater Collection and Treatment	Modeled Emissions	Pounds of emissions
Valves	# in Vapor Service	est. number in service (NumX)
	# in Light Liquid Service	est. number in service (NumX)
	# in Heavy Liquid Service	est. number in service (NumX)
	CVS Service	est. number in service (NumX)
Pumps	# in Light Liquid Service	est. number in service (NumX)
	# in Heavy Liquid Service	est. number in service (NumX)
Compressor Seals	# in gas service	est. number in service (NumX)
Flange/Connector	# in service	est. number in service (NumX)
Spills	Spills	Pounds of emissions
Lab/Sampling Connections	Lab/Sampling Connections	est. number in service (NumX)
Tank #1	Tank #1	1000 barrels
Tank #2	Tank #2	1000 barrels
Tank #3	Tank #3	1000 barrels
Tank #5	Tank #5	1000 barrels
Tank #7	Tank #7	1000 barrels
Tank #8	Tank #8	1000 barrels
Tank #9	Tank #9	1000 barrels
Tank #10	Tank #10	1000 barrels
Tank #12	Tank #12	1000 barrels
Tank #13	Tank #13	1000 barrels
Tank #14	Tank #14	1000 barrels
Tank #16	Tank #16	1000 barrels
Tank #20	Tank #20	1000 barrels
Tank #21	Tank #21	1000 barrels
Tank #33	Tank #33	1000 barrels
Tank #41	Tank #41	1000 barrels
Tank #42	Tank #42	1000 barrels

Point Name	Segment	Throughput Variable
Tank #45	Tank #45	1000 barrels
Tank #46	Tank #46	1000 barrels
Tank #47	Tank #47	1000 barrels
Tank #48	Tank #48	1000 barrels
Tank #49	Tank #49	1000 barrels
Tank #52	Tank #52	1000 barrels
Tank #53	Tank #53	1000 barrels
Tank #54	Tank #54	1000 barrels
Tank #55	Tank #55	1000 barrels
Tank #57	Tank #57	1000 barrels
Tank #72	Tank #72	1000 barrels
Tank #74	Tank #74	1000 barrels
Tank #75	Tank #75	1000 barrels
Tank #86	Tank #86	1000 barrels
Tank #87	Tank #87	1000 barrels
Tank #102	Tank #102	1000 barrels
Tank #110	Tank #110	1000 barrels
Tank #0851	Tank #0851	1000 barrels
Tank #1007	Tank #1007	1000 barrels
Tank #1008	Tank #1008	1000 barrels
Tank #1009	Tank #1009	1000 barrels
Tank #1102	Tank #1102	1000 barrels
Tank #1143	Tank #1143	1000 barrels
Tank #2909	Tank #2909	1000 barrels
Coke Handling Equipment	Coke	Tons of Coke Processed
Railcar Clarified Oil Loading	Railcar Clarified Oil Loading	BBL of Oil Loaded
Diesel Engines	Diesel Engines	MMBtu
Gasoline Engines	Gasoline Engines	MMBtu

2. Phillips 66 shall notify DEQ of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to DEQ, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

I. Notification

Phillips 66 shall provide DEQ with written notification of the following dates within the specified time periods:

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

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

3. For every time the Temporary Boiler is brought onsite, Phillips 66 shall provide written notification to DEQ of the initiation of operation within 15 days. The notification will include the year of construction, and natural gas firing rate (ARM 17.8.749).

SECTION III: General Conditions

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

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

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

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

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

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

G. Duration of Permit - Construction or installation must begin or contractual obligations entered into that would constitute substantial loss within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall expire (ARM 17.8.762).

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

Montana Air Quality Permit Analysis
Phillips 66 Company, Billings Refinery
Montana Air Quality Permit (MAQP) #2619-46

I. Introduction/Process Description

A. Source Description – Phillips 66 Company

The Phillips 66 Company, Billings Refinery (Phillips 66) is located at 401 South 23rd Street, Billings, Montana, in the NW¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County. The refinery property is adjacent to the City of Billings and is next to Interstate 90 and the Yellowstone River. Residential properties exist on the west side of the refinery and the United States Postal Service has an office located on the south side of the property.

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

Phillips 66 Pipeline, LLC: Transportation Operations

Phillips 66 Pipeline LLC is a subsidiary of Phillips 66 Company, under which transportation operations are managed. Phillips 66 Pipeline, LLC has loading rack operations adjacent to the refinery operations that are covered under this MAQP. The portions of the source under the management of the Phillips 66 Pipeline, LLC were provided a separate Title V Operating Permit for purposes of facilitating Responsible Official responsibilities in line with management structure. For PSD/NSR, Title V applicability, and MACT permit review purposes, the Transportation Operations and Refinery Operations are considered one source.

Source Description – Jupiter Sulphur, LLC

Jupiter Sulphur, LLC (Jupiter) operates a sulfur recovery operation, within the petroleum refinery area described above, at 2201 7th Avenue South, Billings, Montana. The facility is operated as a joint venture, of which Phillips 66 is a partner. The Jupiter facility consists of three sulfur recovery units. For PSD/NSR, Title V applicability, and MACT permit review purposes, the Jupiter Operations and Refinery Operations are considered one source.

B. Permit History

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

On June 2, 1989, Conoco received an air quality permit to convert an existing 5,000-barrel cone roof tank (#49) to an internal floating roof with double seals. This conversion was necessary in order to switch service from diesel to aviation gasoline storage. The application was given **MAQP #2565**.

On January 29, 1991, Conoco received an air quality permit to construct and operate two 2,000-barrel desalter wastewater break tanks equipped with external floating roofs and double-rim seals. The new tanks were to augment the refinery's ability to control fugitive Volatile Organic Compounds (VOC) emissions and enhance recovery of oily water from the existing wastewater treatment system. The application was given **MAQP #2669**.

On April 19, 1990, Conoco received an air quality permit to construct new equipment and modify existing equipment at the refinery and to construct a sulfur recovery facility, operated by Kerley Enterprises under the control of Conoco, as part of the overall Conoco project. The application was given **MAQP #2619**.

Conoco was permitted to construct a new 13,000-barrels-per-stream-day delayed petroleum coker unit, cryogenic gas plant, gasoline treating unit, and hydrogen system additions. Also, modifications to the existing crude and vacuum distillation units, hydrodesulfurization units, amine treating units and wastewater treatment system were permitted.

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

On December 4, 1991, Conoco was issued **MAQP #2619A** for the construction of a 1,000-barrel hydrocarbon storage tank (T-162). The new tank stores recovered hydrocarbon product from the contaminated groundwater aquifer beneath the Conoco Refinery. Over the years, surface discharges at the refinery contaminated the groundwater with oily hydrocarbon products. The purpose of this project was to recover hydrocarbon product (oil) from the groundwater aquifer beneath the refinery. The hydrocarbon product (oil) is pumped out of a cone of depression within the contaminated groundwater aquifer. Groundwater, less the recovered hydrocarbon product, is returned to the aquifer. The application addressed the increase in VOC emissions from the storage of recovered hydrocarbon product.

On March 5, 1993, Conoco was issued **MAQP #2619-02** for the construction and operation of a 5.0-MMscf-per-day hydrogen plant and to replace their existing American Petroleum Institute (API) separator system with a CPI separator system. This permit was an alteration to Conoco's existing MAQP #2619 and included all previously permitted equipment, limitations, conditions, and reporting requirements stated in MAQPs #1719, #2565, #2669, #2619, and #2619A.

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

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

As per a letter received by the Department of Environmental Quality (DEQ), on December 22, 1992, ownership of the Kerley Enterprises facility was transferred to Jupiter Sulphur, Inc. as of December 31, 1992.

On September 14, 1993, Conoco was issued **MAQP #2619-03** for the construction and operation of a gas oil hydrotreater and associated hydrogen plant at the Billings Refinery. The new hydrotreater desulfurizes a mixture of Fluid Catalytic Cracker Unit (FCCU) feed gas oils, which allows the FCCU to produce low-sulfur gasoline. This low-sulfur gasoline was required by January 1, 1995, to satisfy Environmental Protection Agency's (EPA) gasoline sulfur provisions of the Federal 1990 Clean Air Act Amendments. Hydrogen requirements are met by the installation of a hydrogen plant, and sulfur recovery capacity was provided by installing additional elemental liquid sulfur production facilities at the Jupiter Sulphur, Inc. plant adjacent to the refinery.

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

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

The additional fugitive VOC emissions from this project were calculated by totaling the fugitive sources on the process units. These sources included flanges, valves, relief valves, process drains, compressor seal degassing vents and accumulator vents and open-ended lines. The fugitive source tabulation was then used with actual refinery emission factors obtained from the Conoco Refinery in Ponca City, Oklahoma.

Furthermore, it was intended that each non-control valve in VOC service would be repacked with graphite packing to Conoco standards before installation. All control valves for the GOHDS project would be Enviro-Seal valves or equivalent. The Enviro-Seal valves have a performance specification that exceeds the Subpart GGG standards. The VOC emissions will be validated by 40 CFR 60, Subpart GGG, emission monitoring.

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

The existing ATS plant consisted of a thermal Claus reaction-type boiler. The exit gas from this Claus boiler is incinerated in the ATS Unit. The SO_2 from the incinerator is absorbed and converted to ammonium bisulfite (ABS). The ABS is then used to absorb and react with H_2S to produce the ATS product. Up to 110 LT/D of sulfur can be processed by the ATS Plant to produce sulfur and ATS.

The ASD consists of an absorption column, which absorbs the sulfur as H_2S in the acid gas feed and reacts with NH_3 and water. When the new Claus Sulfur Unit was added, the Sulfur Recovery Facility was modified to incinerate any off gas from this unit in the TGTU and ATS Plant. This eliminates off-gas flow to, and emissions from, the flare. Up to 110 LT/D of sulfur can be processed by the ASD to produce ammonium sulfide solution.

The proposed Claus Sulfur Unit consisted of a thermal Claus reaction furnace, followed by a waste heat boiler and three catalytic Claus reaction beds. The Claus tail gas is then incinerated before entering the TGTU. In this new unit, SO_2 from the incinerator was absorbed and converted to ABS. This ABS is then transferred to the ATS Unit for conversion to ATS. Up to 110 LT/D of sulfur can be processed by the new Claus Sulfur Unit to produce sulfur and ABS. The ABS from the TGTU is dilute, containing a significant amount of water that was generated from the Claus reaction. To prevent making a dilute ATS from this "weak" ABS, a new ATS Reactor was added to the ATS Unit. This ATS Reactor combines "weak" ABS, additional ABS, and sulfur to make a full-strength ATS solution.

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

On November 11, 1993, Conoco was issued **MAQP #2619-04** to construct and operate a new compressor station and associated equipment at the Billings Refinery. The C-23 compressor station project involved the recommissioning of an out-of-service compressor and associated equipment components having fugitive VOC emissions. The project also involved the installation of new equipment components having fugitive VOC emissions. The recommissioned compressor was originally installed in 1948. The compressor underwent some minor refurbishing, but did not trigger "reconstruction" as defined in 40 CFR 60.15.

The purpose of the C-23 compressor station project was to improve the economics of the refinery's wet gas (gas streams containing recoverable liquid products) processing through increased yields and more efficient operation in the refinery's large and small Crude Topping Units (CTUs) and the Alkylation Unit. The project also improved safety in the operations of the two CTUs, Alkylation Unit, and Gas Recovery Plant (GRP). As a result of this project, the vapor pressure of the alkylate product (produced by the Alkylation Unit) was lowered.

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

The Alkylation Unit Butane Defluorinator Project resulted in: (1) changes in operation of the alkylate stabilization train of the Alkylation Unit to yield defluorinated butane instead of fluorinated and lower vapor pressure alkylate products; (2) changes in operation of the refinery's gasoline blending to restructure butane blending and lower the vapor pressure of the gasoline pool; (3) minimized butane sales; (4) minimized butane burning as refinery fuel gas; and (5) economized gasoline blending of butane.

On March 28, 1994, Conoco was issued **MAQP #2619-06** to construct and operate equipment to support a new PMA Unit at the refinery. The PMA project allowed Conoco to produce asphalt that meets the new federal specifications and to become a supplier of PMA for the region.

Installation of a 9.5-million British thermal units per hour (MMBtu/hr) natural gas-fired process heater to heat an oil heat transfer fluid supplies heat to bring the asphalt base to 400°F. This allows a polymer material to be mixed with it to produce PMA. A hot oil transfer pump was installed to circulate hot oil through the system. A heat exchanger (X-364) from the shutdown Propane De-asphalting (PDA) Unit was moved and installed to aid in the heating of the asphalt base. Two existing 5,000-bbl asphalt storage tanks were converted to PMA mixing and curing tanks. This required the installation of additional agitators, a polymer pellet loading (blower) system and conversion of the tank steamcoil heating system to hot oil heated by the new process heater. New asphalt transfer lines, a new asphalt transfer pump, and a new 5,000-bbl PMA storage tank (to replace the demolished T-50) were installed to keep the PMA separated from other asphalt products. This permit alteration also addressed the items submitted in a letter dated November 23, 1993, for supplemental information and a request for permit clarification for Conoco's MAQP #2619-03. This permit clarifies all these items, as appropriate, including the issues relating to the redesign of the SRU stack and the addition of heated air to the stack. Reference Section V, Air Quality Impacts.

On July 28, 1995, Conoco was issued **MAQP #2619-07** for the construction and operation of new equipment within the refinery's Alkylation (Alky) and Gas Recovery Plant/No.1 Amine Units. The project was referred to as the Alkylation Unit Depropanizer Project.

The existing Alkylation Unit was replaced with a new tower. The new depropanizer is located where the No.1 Bio-pond was located. Piping and valves were added, and existing equipment was located next to the new depropanizer. The old depropanizer was retained in place and may be used in the future in non- HF service.

The decommissioned PDA Unit evaporator tower (W-3) was converted to a water wash tower to remove entrained amine from the Alky PB (Propane/Butene) olefins upstream of the PB merox prewash. New piping, valves, and instrumentation were added around W-3.

The change in air emissions associated with this project was an increase in fugitive VOC emissions, as well as additional emission of fluorides due to the installation of the new depropanizer piping and valves.

The changes made by this project were not subject to NSR-PSD review since the sum of the emission rate increases were below PSD significant emission rates for applicable pollutants.

The drains installed or reused tie into parts of the refinery's wastewater sewer system that are already subject to Standards of Performance for New Stationary Sources (NSPS), Subpart QQQ (Wastewater Treatment System VOC Emissions in Petroleum Refineries) and National Emission Standards for Hazardous Air Pollutants (NESHAP), Subpart FF (Benzene Waste Operations). These drains were equipped with tight fitting caps and have hard pipe connections to meet the required control specifications.

On July 24, 1996, Conoco was issued **MAQP #2619-08** to change the daily SO_2 emissions limit of the 19 existing process heaters, as well as combining the 19 heaters, the Coker heater (H-3901), and the GOHDS heaters (H-8401 and H-8402) into one SO_2 point source within the Refinery. The project is referred to as the Existing Heater Optimization Project.

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

Also included in this discussion are the Coker heater (H-3901) and the GOHDS heaters (H-8401 and H-8402).

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

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

The DEQ received comments from Conoco, in which Conoco contends that the maximum heat input (MMBtu/hr) from the AFS does not accurately reflect the real maximum firing rates of the heaters. After further review of the files, DEQ established the total maximum firing rate for the (19) Refinery Fuel Gas Heaters/Furnaces to be 785.5 MMBtu/hr. This total maximum firing rate was identified by Conoco during the permit review of the Coker permit (MAQP #2619). The maximum heat input of 785.5 MMBtu/hr and the fuel heat of 958 Btu/scf are used to calculate a new daily "bubble" SO_2 permit limit of 529.17 lb/day.

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

Even though Conoco's past annual average fuel gas H_2S content was below 37.8 ppmv, there was still potential to run into operational limitations in peak fuel gas demand periods. The amine systems may not be able to keep the fuel gas H_2S under

49.75 ppmv, rendering the refinery to operate at un-optimized rates. This was the reason for the request to raise the daily SO_2 emissions limit for the "19-Heater" source. Since the proposed change to the heaters' SO_2 emissions limit does not reflect an annual increase in PTE, the project is not subject to PSD permitting review (threshold for SO_2 is 40 TPY).

In light of the SO_2 problem in the Billings-Laurel air shed, any change resulting in an increase of SO_2 emissions must have its impact determined to see if any National Ambient Air Quality Standards (NAAQS) will be violated as a result of the project. SO_2 modeling was completed by DEQ to develop a revised SO_2 SIP for the Billings-Laurel area (see the Billings/Laurel SO_2 SIP Compliance Demonstration Report dated November 15, 1994). The "19-Heater source" was modeled using an SO_2 emission rate equivalent to 111.7 TPY to determine its SO_2 impact on the Billings-Laurel air shed. The results of this modeling showed there were no exceedances of the SO_2 NAAQS or the Montana standards resulting from its operation. Therefore, an increase in the permit limit from 164 lb/day to 612 lb/day of SO_2 did not result in any violations of SO_2 NAAQS or Montana standards; however, the daily emission limit set based on the NSPS limit of 0.1 grains per dry standard cubic foot (gr/dscf) (160 ppmv H_2S) is more restrictive than the SIP limit. The daily emission limit, based on NSPS, is 529.17 lb/day for the existing 19 heaters/furnaces.

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

On April 19, 1997, Conoco was issued **MAQP #2619-09** to "bubble" or combine the allowable hourly and annual NO_X emission limits for the Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heaters. The NO_X emission limits for these heaters were established on a pounds-per-million-Btu basis, and will be maintained.

By "bubbling" or combining the allowable hourly and annual NO_X emission limits for the Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heaters allows Conoco more operational flexibility with regard to heater firing rates and heater optimization. The Coker heater still has an hourly NO_X emission limit to prevent any significant impacts. This permit alteration does not allow an increase in the annual NO_X emissions. MAQP #2619-09 replaced MAQP #2619-08.

On July 30, 1997, **MAQP #2619-10** was issued to Conoco in order to comply with 40 CFR 63, Subpart R, National Emission Standards for Gasoline Distribution Facilities. Conoco installed a gasoline vapor collection system and enclosed flare for the reduction of Hazardous Air Pollutants (HAPs) resulting from the loading of gasoline. The vapor combustion unit (VCU) was added to the bulk gasoline and distillate loading rack. The gasoline vapors were collected from the trucks during loading, then routed to an enclosed flare, where combustion occurs. The project results in overall reductions in the amount of actual emissions of VOCs (94.8 TPY), with a slight increase in CO (2.1 TPY) and NO_X (0.8 TPY) emissions. The actual reduction in potential emissions of VOCs is 899.5 TPY, while CO increases to 19.7 TPY and NO_X increases to 7.9 TPY emissions.

In addition, Conoco requested an administrative change be made to Section II.F.5, which brought the permit requirements in alignment with the monitoring requirements specified by 40 CFR 60, Subpart QQQ, and 40 CFR 61, Subpart FF.

Because Conoco's Bulk gasoline and distillate loading tank VCU is defined as an incinerator under Montana Code Annotated (MCA) 75-2-215, a determination that the emissions from the VCU constitutes a negligible risk to public health is required prior to the issuance of a permit to the facility. Conoco and DEQ identified the following HAPs from the flare, which were used in the health risk assessment. These constituents are typical components of gasoline.

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

The reference concentrations for Ethyl Benzene, Hexane, and Methyl Tert Butyl Ether were obtained from EPA's IRIS database. The risk information for the remaining HAPs is contained in the January 1992 CAPCOA Risk Assessment Guidelines. The model performed by Conoco for the HAPs identified above, demonstrate compliance with the negligible risk requirement. MAQP #2619-10 replaced MAQP #2619-09.

On December 10, 1997, Conoco requested a modification to allow the continuous incineration of a PB Merox Unit off-gas stream in the firebox of Heater #16. MAQP #2619-10 required the production of SO_2 from the sulfur containing compounds in the PB Merox Unit off-gas stream to be calculated and counted against the current SO_2 limitations applicable to the (22) Refinery Fuel Gas Heaters/Furnaces group. During a review of process piping and instrumentation diagrams, Conoco identified a PB Merox Unit off-gas stream incinerated in the firebox of Heater #16. A subsequent analysis of this off-gas stream revealed the presence of sulfur-containing compounds in low concentrations. The bulk of this low-pressure off-gas stream is nitrogen with some oxygen, hydrocarbons, and sulfur-containing compounds (disulfides, mercaptans). SO_2 produced from the continuous incineration of this stream has been calculated at approximately 1 TPY. This off-gas stream is piped from the top of the disulfide separator through a small knock-out drum and directly into the firebox of Heater #16.

Conoco proposed to sample the PB Merox Unit disulfide separator gas stream on a monthly basis to determine the total sulfur (ppmw) present. This analysis, combined with the off-gas stream flow rate, is used to calculate the production of SO_2. After a year of sampling time and with the approval of DEQ, Conoco may propose to reduce the sampling frequency of the PB Merox disulfide separator off-gas stream to once per quarter if the variability in the sulfur content is small (250 ppmw).

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

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

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

> In previously issued permits, Section II.A.4 listed storage tanks #4510 and #4511 as having external floating roofs with primary seal, which were liquid mounted stainless steel shoes and secondary seal equipped with a Teflon curtain or equivalent. Conoco stated that these two tanks were actually equipped with internal floating roofs with double-rim seals or a liquid-mounted seal system for VOC loss control.
>
> Section II.A.7.g.ii always listed the CPI separators as primary separators, when in fact they are secondary.

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

On March 1, 2001, DEQ issued **MAQP #2619-13** for the installation and operation of 19 diesel-powered, temporary generators. These generators are necessary because of the high cost of electricity and supplement 18 MW of the refinery's electrical load, and 1 MW of Jupiter's electrical load. The generators are located south of the coke loading facility along with two new aboveground 20,000-gallon diesel storage tanks. The operation of the generators will not occur beyond 2 years and is not expected to last for an extended period of time, but rather only for the length of time necessary for Conoco to acquire a permanent, more economical supply of power.

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

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

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

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

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

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

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

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

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

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

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

2. No. 2 H_2 Unit PSA Offgas Vent (45) is to be added.

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

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

5. The dimensions, secondary rim seal, and specific deck fittings data for the No.5 HDS Feed Tank to be updated. The tank is proposed to store material

with a maximum true vapor pressure of 11.1 pounds per square inch at atmosphere (psia).

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

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

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

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

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

11. In accordance with Paragraph 54 of the Consent Decree the FCCU became subject to the SO_2 portions of Standards of Performance for New Stationary Sources (NSPS), Subpart J on February 1, 2005.

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

MAQP #2619-21 replaced MAQP #2619-20.

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

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

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

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

SO_2 50 ppmvd emission limit established for the FCCU shall not apply during periods of hydrotreater outages (requested February 1, 2006)

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

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

The DEQ received two requests from ConocoPhillips for modifications to the permit in conformance with requirements contained in their Consent Decree (Civil Action #H-01-4430):

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

- 8/29/07 – request to clarify that the FCCU is subject to a PM emission limit of 1 lb per 1,000 lb of coke burned, and that it is an affected facility subject to 40 CFR 60, Subparts A and J, including the 30% opacity limitation. The requirement to maintain less than 20% opacity was then removed, since the FCCU became subject to the 30% Subpart J opacity limit which supersedes the ARM 17.8.304 opacity limit.

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

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

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

On June 12, 2009, DEQ received a request from ConocoPhillips to administratively amend MAQP #2619-24 to include certain limits and standards. This amendment was in response to requirements contained in the Consent Decree (CD) that ConocoPhillips has entered into with EPA along with DEQ. The CD was set forth on December 20, 2001. As a result of the requirements set forth within the CD, ConocoPhillips had requested the following limits and standards (agreed to by EPA) to be included in the MAQP:

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

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

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

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

NO_x emissions shall not exceed 49.2 ppmvd corrected to 0% O_2, on a rolling 365-day average and 69.5 ppmvd, corrected to 0% O_2, on a rolling 7-day average. The 7-day NO_x emission limit shall not apply during periods of hydrotreater outages, provided that ConocoPhillips is maintaining and operating the FCCU (including associated air pollution control equipment) consistent with good air pollutions control practices for minimizing emissions in accordance with the EPA-approved good air pollution control practices plan. 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). ConocoPhillips requested this addition in language as a result of an April 29, 2011 letter from EPA, which contained the formal approval of the FCC NOx emission limits required by the CD. The letter included EPA's expectations as to how these NOx emission concentration averages are to be calculated. This amendment to MAQP #2619-25 included the requested changes from the December 6, 2010, and July 28, 2011, administrative amendment requests.

As a result of both of these requests, **MAQP #2619-27** replaced MAQP #2619-25. On September 13, 2011, October 7, 2011, October 25, 2011, and October 31, 2011, DEQ received elements to fulfill a complete air quality permit application from ConocoPhillips. ConocoPhillips requested a modification to their existing air quality permit to incorporate conditions and limitations associated with the proposed installation of a Backup Coke Crusher. A Backup Coke Crusher is necessary to ensure crushed coke is available at all times for the facility, particularly during instances when the main Coke Crusher is not operational as a result of mechanical failure and/or maintenance activities. The components of the Backup Coke Crusher include the coke crushing unit as well as a diesel fired engine and compressor.

This permit action incorporated all limitations and conditions associated with the proposed Backup Coke Crusher. **MAQP #2619-28** replaced MAQP #2619-27.

On May 3, 2012, DEQ received a request to administratively amend MAQP #2619-28 to incorporate a change in the ConocoPhillips Company name. On May 1, 2012, the downstream portions of the ConocoPhillips Company were spun-off as a separate company named Phillips 66 Company (Phillips 66). As a result of the spin-off, the former ConocoPhillips Billings Refinery is now the Phillips 66 Billings Refinery. The permit action incorporated the name change throughout, and **MAQP #2619-29** replaced MAQP #2619-28.

On October 9, 2012, DEQ received an Administrative Amendment Request to delete conditions regarding the New Crude and Vacuum Unit because the project was cancelled, clarification of various rule applicabilities and other minor edits. A letter outlining the requested changes in bullet point fashion is on file with DEQ. **MAQP #2619-30** replaced MAQP #2619-29.

On May 1, 2014, DEQ received an Administrative Amendment request from Phillips 66. Phillips 66 is in the process of taking steps to close out the Consent Decree with the Environmental Protection Agency (EPA) and the State of Montana. Phillips 66 requested that limits and standards from the Consent Decree which are required to live on beyond the life of the Consent Decree be present in the permit, with authority for those conditions to rest outside of regulatory reference to the Consent

Decree itself. The action removed references to the Consent Decree as a regulatory basis. The changes taking place in this action are tabelized below. Following the first table is a table which contains additional information regarding all conditions in the MAQP which are believed to have originated through the Consent Decree. **MAQP #2619-31** replaced MAQP #2619-30.

MAQP #2619-31 Table 1: Changes taking place in this action

MAQP #2619-30 Condition	Source	Pollutant	Obligation	CD Paragraph	Prior Permit Reference	New Regulatory Reference
II.E.5.c.i	Boiler Stack	SO_2	CEMS	71	CD	17.8.749
II.C.1.d.ii	FCC	SO_2	7-day & 365-day limits	40	CD	17.8.749
II.C.1.d.vi	FCC	NOx	7-day & 365-day limits	17	CD	17.8.749
II.C.1.d.iv	FCC	CO	365-day limit	50	CD	17.8.749
II.C.1.d.v	FCC	CO	1-hr limit	49	CD	17.8.749
II.C.1.d.vii	FCC	PM	1 lb/1000 lb coke burn	46, 47(a)	CD	17.8.749
II.A.1.c.v	FCC	----	NSPS J and A applicability	54	CD	17.8.749
II.C.1.d.iii	FCC	SO_2	NSPS J limit	54	CD	17.8.749
II.C.1.d.vii	FCC	PM	NSPS J limit	54	CD	17.8.749
II.C.1.d.vii i	FCC	Opacity	NSPS J limit	54	CD	17.8.749
II.E.5.b.v	FCC	NOx	CEMS	28	CD	17.8.749
II.E.5.b.iv	FCC	CO	CEMS	49	CD	17.8.749
II.E.5.b.vi	FCC	O_2	CEMS	28, 37	CD	17.8.749
II.E.5.b.i	FCC	SO_2	CEMS	37	CD	17.8.749
II.E.5.b.iii	FCC	Opacity	COMS	47(b)	CD	17.8.749
II.E.4	FCC	PM	Particulate Emissions Test-annual	47(a)	CD	17.8.749
II.B.1	Flare-Refinery	SO_2	RCFAs & FGRS	162	CD	17.8.749
II.A.1.c.iii	Flare-Refinery	SO_2	NSPS J and A applicability	161	CD	17.8.749
II.A.1.c.iv	Flare-Jupiter	SO_2	NSPS J and A applicability	155	CD	17.8.749
II.A.1.c.i	Heaters/Boilers	SO_2	NSPS J applicability	69	none	17.8.749
II.C.1.e.i	Heaters	SO_2	No fuel oil burning	**	none	17.8.749
II.C.1.e.iii	Heaters	SO_2	Limit of 0.10 gr/dscf H_2S in fuel gas	69	none	17.8.749

MAQP #2619-30 Condition	Source	Pollutant	Obligation	CD Paragraph	Prior Permit Reference	New Regulatory Reference
II.C.1.f.iv	Boilers	SO_2	Limit of 0.10 gr/dscf H_2S in fuel gas	69	none	17.8.749
II.C.1.f.ii	Boilers	SO_2	300 ton/365-day rolling avg.***	71	CD	17.8.749
absent	Flare-Jupiter	SO_2	RCFAs for NSPS J	179	none	17.8.749

*** Condition existed in MAQP prior to Consent Decree

** Not in Consent Decree but requested as part of this action

MAQP #2619-31 Table 2: All conditions originating from Consent Decree

Source	CD Limit or Obligation	MAQP #2619-30 Permit Condition	Compliance Demonstration
FCCU	365-Day Rolling Average NO_x Emission =49.2 ppmvd @ 0% O_2 7-Day Rolling Average NOx Emission = 69.5 ppmvd @ 0% O_2 Hydrotreater Outages (7-Day Limit Shall Not Apply)	Sec. II.C.1.d.vi	Sec. II.E.5.b.v Sec. II.E.b.vi Sec. II.E.7 Sec. II.E.8
FCCU	365-Day Rolling Average SO_2 Emission = 25 ppmvd @ 0% O_2 7-Day Rolling Average SO_2 Emission = 50 ppmvd @ 0% O_2 Hydrotreater Outages (7-Day Limit Shall Not Apply)	Sec. II.C.1.d.ii	Sec. II.E.5.b.i Sec. II.E.b.vi Sec. II.E.7
FCCU	PM Emission = 1 lb/1000 lbs coke burned	Sec. II.C.1.d.vii	Sec. II.E.4
FCCU	1-Hour Average CO Emission = 500 ppmvd @ 0% O_2 (Startup, Shutdown, or Malfunctions not used in determining compliance with this limit. - 2nd Amendment) 365-Day Rolling Average CO Emission = 150 ppmvd @ 0% O_2	Sec. II.C.1.d.v Sec. II.C.1.d.iv	Sec.II.E.5.b.iv Sec. II.E.7
FCCU	Must comply with NSPS Subpart A and J - SO_2	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec. II.C.1.d.iii *(Emission Limit)*	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec.II.E.5.b.i *(Emission Monitoring)* Sec. II.E.7 *(Emission Monitoring)*
FCCU	Must comply with NSPS Subpart A and J - PM	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec. II.C.1.d.vii *(CD Emission Limit)*	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec.II.E.4 *(Emission Testing)*

Source	CD Limit or Obligation	MAQP #2619-30 Permit Condition	Compliance Demonstration
FCCU	Must comply with NSPS Subpart A and J - CO	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec. II.C.1.d.v *(CD Emission Limit)*	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec.II.E.5.b.iv *(Emission Monitoring)* Sec. II.E.7 *(Emission Monitoring)*
FCCU	Must comply with NSPS Subpart A and J - Opacity	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec. II.C.1.d.viii *(Emission Limit)*	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec.II.E.5.b.iii *(Emission Monitoring)* Sec. II.E.7 *(Emission Monitoring)*
Boilers	Must comply with NSPS Subpart J (SO_2, CO & PM) 365-Day Rolling Average SO_2 Emissions = 300 tpy (Fuel-Oil Burning Only)	Sec. II.A.1.c.i *(General Condition)* Sec. II.C.1.f.ii *(Emmission Limit)* Sec. II.C.1.f.iii *(Emission Limit)*	Sec. II.A.1.c.i *(General Condition)* Sec. II.E.5.c.i *(Emission Monitoring)* Sec. II.E.7 *(Emission Monitoring)* Sec. II.E.5.e *(Emission Monitoring)*
Heaters	Must comply with NSPS Subpart J (SO_2, CO & PM) 365-Day Rolling Average SO_2 Emissions = 300 tpy (Fuel-Oil Burning Only)	Sec. II.A.1.c.i *(General Condition)* Sec. II.C.1.e.i *(Operating Condition)* Sec. II.C.1.f.iii *(Emission Limit)*	Sec. II.E.5.e *(Emission Monitoring)*
SRU/Ammonium Sulfide Unit Flare (Jupiter Flare)	Must comply with NSPS Subpart A and J.	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.iv *(General Condition)* Sec. II.C.7 *(Operating Condition)*	Sec. II.E.5.f
Main Plant Flare (Refinery)	Must comply with NSPS Subpart A and J.	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.iii *(General Condition)* Sec. II.B.1 *(Control*	Sec. II.E.5.f

Source	CD Limit or Obligation	MAQP #2619-30 Permit Condition	Compliance Demonstration
		Requirement) Sec. II.C.6.a *(Operating Condition)*	
Jupiter SRU/ATS Main Stack	Must comply with NSPS Subpart A and J.	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.ii *(General Condition)*	
Main Plant Flare (Refinery)	Root Cause Failure Analysis	Sec. II.C.6	

On September 16, 2014, DEQ received an application from Phillips 66 to propose physical and operational changes to process units and auxiliary facilities at the refinery in order to provide more optimized operations for a broader spectrum of crude oil slates. This application was assigned **MAQP #2619-32**. Changes were primarily related to certain crude distillation, hydrogen production and recovery, fuel gas amine treatment, wastewater treatment, and sulfur recovery equipment and operations. A detailed list of project-affected equipment with a description of the changes proposed is presented below:

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
Small Crude Unit Heater, H-1	Existing	55.92 MMBtu/hr (HHV)	The tubes in the Small Crude Unit Heater, H-1 will be replaced with upgraded metallurgy tubes. Phillips 66 has not sought to treat this change as qualifying for one of the exemptions from what is a physical change or change in the method of operation under relevant PSD regulations.
Vacuum Furnace, H-17 – Existing Furnace	Existing	n/a	This emissions unit will be discontinued from service and replaced by a new process heater, as noted below.
Vacuum Furnace, H-17 – Replacement Furnace	New	75 MMBtu/hr (HHV)	This emissions unit will be constructed to replace the refinery's existing Vacuum Furnace, H-17, which, as noted above, will be removed from service.

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
FCCU Preheater, H-18	Existing	77 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project because the actual feed rate (and the gas oil content of the feedstock) to the No. 4 HDS Unit, which provides the feed to this heater, is anticipated to increase due to the project. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
Large Crude Unit Heater, H-24	Existing	108.36 MMBtu/hr (HHV)	This emissions unit will be physically modified, including the installation of upgraded metallurgy tubes to replace the existing tubes in the heater and the installation of ULNBs to replace the existing burners in the heater.
FCCU Stack	Existing	8,285.50 million barrels per year (gas oil feed)	Phillips 66 estimated that the project would result in an increase in the actual FCCU catalyst regenerator coke burn rate equal to approximately 12% of its annual average potential to emit coke burn rate. This coke burn rate increase will be associated with the actual increase in throughput and slightly heavier gas oil feedstock expected for the FCCU. The increase in throughput and gas oil feedstock density for the FCCU will occur because the No. 4 HDS Unit, which provides the feed to the FCCU, is estimated to experience an increase in the gas oil content of its feed, as well as an overall increase in its actual feed rate, as a result of the project. These changes to the No. 4 HDS Unit feed will occur because of the improved separation capabilities of the new Vacuum Unit Fractionator (W-57). The estimated increase in actual FCCU catalyst regenerator coke burn rate will make use of existing coke burn rate capacity that is not currently being utilized. The project does not propose to increase the coke burn rate capacity or the potential to emit emission rates of the FCCU catalyst regenerator.

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
Storage Tanks	Existing		Certain storage tanks at the refinery are anticipated to experience an increase in actual annual throughput primarily because of the improved straight run diesel and gas oil separation operations that will occur as a result of the project. This improvement in straight run diesel and gas oil separation will generally result in an increase in the throughput for diesel and gas oil storage tanks at the refinery. On the other hand, certain storage tanks at the refinery will experience a decrease in actual annual throughput as a result of the project. The refinery storage tanks expected to experience a decrease in throughput are those tanks that generally store lighter (higher vapor pressure) materials, such as gasoline and gasoline blendstocks. These actual throughput decreases have not been evaluated for PSD applicability determination purposes (*i.e.*, any emissions decreases that may result due to these throughput decreases have not been estimated because Phillips 66 does not intend to make such emissions decreases creditable). Additionally, the Desalter Break Tanks (T-4510 and T-4511) at the refinery will be removed from service and replaced by two new API separator bays (including associated equipment).
Fugitive VOC Emissions	Existing-New		New piping fugitive components (*e.g.*, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, and flanges or other connectors) are expected to be added to the refinery as a result of the project due to certain piping and equipment additions that will occur as part of the project. Also, new process drains and junction boxes are anticipated to be added to the refinery as part of the project. Furthermore, the Primary OWS (T-163) at the refinery will be removed from service and replaced by two new API separator bays (including associated equipment).
CPI Separator Tanks	Existing		The OWSs (CPI OWSs (T-169 and T-170)) representing this emissions unit are planned to be removed from service and replaced by two new API separator bays (including associated equipment).
No. 4 HDS Recycle Hydrogen Heater, H-8401	Existing	31.20 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in an increase in the actual feed rate to the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
No. 4 HDS Fractionator Feed Heater, H-8402	Existing	31.70 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in an increase in the actual feed rate to the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
No. 1 H_2 Unit Reformer Heater, H-9401	Existing	179.20 MMBtu/hr PSA Gas, HHV 76.80 MMBtu/hr Natural Gas/Cryo Gas, HHV	Modifications will be made to the burners in the No. 1 H_2 Unit Reformer Heater, H-9401 (EPN 35) to improve the flame pattern of these burners and to reduce hot spots on the tubes located in this heater. The type of burner modification may include changing the angle of the burners relative to this heater's tubes. Phillips 66 has not sought to treat this change as qualifying for one of the exemptions from what is a physical change or change in the method of operation under relevant PSD regulations.
Coke Handling	Existing		Based on engineering calculations, the actual annual coke production rate of the Coker Unit is expected to increase as a result of the project due to the heavier vacuum residuum that will be sent to the Coker Unit after the implementation of the project. Therefore, the actual annual amount of coke handled at the refinery is expected to increase as a result of the project.
No. 5 HDS Charge Heater, H-9501	Existing	25.0 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project primarily because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in more diesel range material being routed to the No. 5 HDS Unit rather than the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
No. 5 HDS Stabilizer Reboiler Heater, H-9502	Existing	49.00 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project primarily because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in more diesel range material being routed to the No. 5 HDS Unit rather than the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
No. 2 H_2 Unit Reformer Heater, H-9701	Existing	111.35 MMBtu/hr PSA Gas, HHV 79.65 MMBtu/hr Natural Gas/Cryo Gas, HHV	The actual feed rate to this process heater is anticipated to increase as a result of the project in order to provide a portion of the increase in hydrogen production expected to be required by the project. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 15% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
Coker Vent and Coke Cutting	Existing		Based on engineering calculations, the actual annual coke production rate of the Coker Unit is expected to increase as a result of the project due to the heavier vacuum residuum that will be sent to the Coker Unit after the implementation of the project. In association with this annual coke production rate increase is a decrease in coke drum cycle time. Therefore, the actual annual number of coke drum opening and coke cutting events is expected to increase as a result of the project.
Cooling Tower	New	7,000 gallons per minute	This cooling tower will be newly constructed to accommodate the increase in cooling water demand estimated to be required by the modified Vacuum Unit.
Railcar Clarified Oil Loading	Existing		The existing railcar clarified oil loading operation at the refinery is anticipated to experience an increase in annual throughput relative to the current annual throughput at which this operation typically operates due to the higher annual operating rate expected for the FCCU as a result of the project.

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
API Separator Tanks	New	132,058 thousand gallons per year	The OWSs representing this emissions unit will replace the following equipment currently located at the refinery: (1) Desalter Break Tanks (T-4510 and T-4511); (2) Primary OWS (T-163); and (3) CPI OWSs (T-169 and T-170). The Oil Water Separator system includes the separator tanks themselves and associated equipment. See 40 CFR §63.1041 definition of Separator. The oil water separator system includes the slop oil vessel (T-4526) and Sludge Hopper (T-4527).
Jupiter Main Stack No. 1	Existing		SRU No. 1, which emits through this stack, will experience multiple physical changes to accommodate a portion of the increased amount of sulfur-containing compounds that will be routed to the Jupiter Plant as a result of the project.
Jupiter Main Stack No. 2	New		SRU No. 3, which will emit through this stack, will be newly constructed as part of the project to accommodate a portion of the increased amount of sulfur-containing compounds that will be routed to the Jupiter Plant as a result of the project.
Jupiter Cooling Tower, CT-615A/B/C	New	7,500 gallons per minute	This cooling tower will be newly constructed to accommodate the increase in cooling water demand estimated to be required by the Jupiter Plant as a result of the project.
Jupiter Cooling Tower CT-120	New	11,500 gallons per minute	This cooling tower will replace the existing cooling tower located at the Jupiter Plant. This Cooling Tower was approved via de minimis after initial permitting of the Vacuum Improvement Project. As required by the de minimis provisions of ARM 17.8.745, review occurred to ensure the emissions from the cooling tower would not have triggered need for PSD permitting for the Vacuum Improvement Project.
Jupiter Sulfur Storage Tanks	Existing-New		The two existing atmospheric sulfur storage tanks (V-117 and V-355) at the refinery may experience an increase in actual annual throughput due to improved sulfur recovery operations of the respective SRUs associated with these tanks and an increase in sulfur loading to the same respective SRUs. Additionally, a new atmospheric sulfur storage tank (V-370) is proposed to be installed at the refinery as part of the project.
Jupiter Railcar and Tank Truck Sulfur Loading	Existing-New		The existing railcar and tank truck sulfur loading arms at the refinery may experience an increase in actual annual throughput as a result of the project. Additionally, one new railcar sulfur loading arm and one new tank truck sulfur loading arm are planned to be installed at the refinery as part of the project.

On September 21, 2015, DEQ received an administrative amendment request from Phillips 66 to clarify certain provisions and emission limits that were initially adopted under the consent decree. The revisions also address the triggering of 40 CFR 60 Subpart Ja for certain units, including flares. Per 40 CFR 60 Subpart Ja, flares which have triggered Subpart Ja and were meeting Subpart J requirements pursuant to a federal consent decree, will continue to meet those requirements until November 11, 2015, at which time all the requirements of Subpart Ja will apply. The requested permit changes included clarification of how the modified flares will comply before and after November 11, 2015. **MAQP #2619-33** replaced MAQP #2619-32.

On March 14, 2016, DEQ received from Phillips 66 a request for an administrative amendment of the MAQP. Changes requested include updating information regarding the cooling towers to be installed as part of the Vacuum Improvement Project to reflect changes made and approved through the de minimis provisions of ARM 17.8.745, and to correct an error regarding identification of tanks which will be removed from service as part of the Vacuum Improvement Project. Lastly, the letter received on March 14th provided notice regarding a change in stack height for the Large Crude Unit Heater H-24, from 152 feet to 195 feet 10 inches. No revision to the MAQP was necessary for the stack height change and a separate de minimis approval letter was sent to Phillips 66 regarding this change. **MAQP #2619-34** replaced MAQP #2619-33.

On April 24, 2017 DEQ received from Phillips 66 a request for an administrative amendment of the MAQP to clarify equipment associated with the API Separator System being installed as part of the Vacuum Improvement Project. Specifically, this permit update clarifies that the API Separator System includes the "Slop Oil Vessel T-4526" and the "Sludge Hopper T-4527". P66 has requested this clarification to ensure that equipment installed on-site is understood to have been included at the time of permitting of the Vacuum Improvement Project. DEQ agreed, and noted that the Separator System consists of equipment which includes the aforementioned units, and in fact, the definition of a Separator in relevent federal rules includes not only the separation unit itself but also the forebay and other separator basins and sludge hoppers, amongst other equipment (see 40 Code of Federal Regulations (CFR) §63.1041). Section II.J.7 of the MAQP was updated to reflect the separator system.

The permit was also updated to reflect the de minimis addition of a residuum tank, identified as Tank # T-0852, to condition II.A.3.c. This tank will hold crude distillation residuum and will allow the existing Tank 107 to be temporarily taken out of service for inspections. **MAQP #2619-35** replaced MAQP #2619-34.

On March 29, 2018, DEQ received from Phillips 66 an application to modify the oxides of nitrogen (NO_X) emissions limitations associated with the No. 1 H_2 Plant Reformer Heater, H-9401. Based on source testing, the 0.030 pound per million british thermal units (lb/MMBtu) NO_X emissions limit was found not achievable. Because this heater was modified as part of the Vacuum Improvement Project, the current action entails a Prevention of Significant Deterioration (PSD) lookback to this project. The analysis as completed at that time is essentially re-worked utilizing the higher NO_X emissions factor now applied to the heater. The netting analysis is included in the permit analysis, and the increases do not change the status of the Vacuum Improvement Project as not triggering PSD for NO_X.

Additional information was received on April 23rd regarding the limit and determination of applicable federal rules. On April 24, 2018, DEQ received an affidavit of publication of public notice, completing the application.

This permit action modified NO_X limits associated with this heater to 0.042 lb/MMBtu. **MAQP #2619-36** replaced MAQP #2619-35.

On December 20, 2018, DEQ received from P66 an application to modify the MAQP and Title V to add two backup engines to the facility, a 665 horsepower (hp) portable backup fire pump and a 300 hp emergency backup engine for redundant HDS Flare Drum Pumps. A limit of operation of 1,000 hours is proposed for the Flare Drum Pump engine. Both engines are to be Tier III rated. At the request of P66, the permit action incorporated these engines and corresponding limitations. **MAQP #2619-37** replaced MAQP #2619-36.

On January 10, 2020, DEQ received from Phillips 66 Company an application to change particulate matter emissions limitations associated with the Sulfur Recovery Operations. Following construction and commencement of operation of modifications made in support of and permitted as part of the Vacuum Improvement Project in MAQP #2619-32, the emissions of particulate matter as measured by Environmental Protection Agency (EPA) Methods 201a and 202 were found to be in excess of that allowed by permit conditions.

Following extensive review by Phillips 66 and Jupiter Sulphur, LLC to minimize emissions including condensable emissions, based on additional source testing, the limitations were determined unachievable. The current action increases the allowable emissions from Main Stack 1 and 2 to levels proposed as achievable by Phillips 66. Because these limits were established as part of the Vacuum Improvement Project, and the limits served in part to define allowable emissions which ensured the project did not exceed thresholds triggering the Prevention of Significant Deterioration (PSD) requirements of ARM 17.8 Subchapter 8, the current action is reviewed as if re-permitting the action of MAQP #2619-32. In doing so, the project triggers PSD for particulate matter, particulate matter with aerodynamic diameter of 10 microns or less, and particulate matter with aerodynamic diameter of 2.5 microns or less. The project also triggers PSD for greenhouse gasses. On March 3, 2020, DEQ received modified application information in response to an incompleteness letter.

MAQP #2619-38 increases allowable particulate matter related emissions from Jupiter Main Stacks 1 and 2, and reviews greenhouse gas best available control technology for the physically modified and new emitting units associated with the Vacuum Improvement Project.

On September 23, 2020, DEQ received from Phillips 66 an MAQP application for significant changes to the refinery. The application triggers the Prevention of Significant Deterioration (PSD) program requirements of ARM 17.8 Subchapter 8 for oxides of nitrogen (NO_X), particulate matter with an aerodynamic diameter of 2.5 microns and less ($PM_{2.5}$), particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), and greenhouse gases (GHGs). The project also triggers PSD for ozone based on NO_X.

The refinery is currently designed to refine heavy sour crude oil. In general, this permitting action is a conglomeration of several projects which will ultimately provide Phillips 66 the ability to process crude oils that contain higher percentages of residual material while also maintaining compliance with fuel sulfur content requirements (i.e. – process heavier, sour crude). Physical changes are expected to the crude units, coker unit, fluidized catalytic cracking unit (FCCU), the propylene and butylene mercaptan extracting unit (PB Merox Unit), and the sulfur recovery units (SRUs) at the adjacent Jupiter plant. Additionally, a new hydrogen plant, hydrogen plant #3, will be installed. Changes in operation will also affect emissions from several existing heaters and unit operations including the delayed coking unit.

The permit analysis contains a table detailing all changes proposed to project affected emitting units, as well as a presentation of the net emissions changes, best available control technology (BACT) determinations, and a summary of the ambient air quality impacts including increment consumption.

Relevant permit conditions have been included throughout the permit. In addition, conditions created relevant to the Vacuum Improvement Project, which originally had its own section, have been incorporated into the rest of the permit.

Emissions Unit	Existing/ New Unit	Project Impact
Catalytic Reforming Unit #2 (H-13) (EPN 64)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 2.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.

Emissions Unit	Existing/ New Unit	Project Impact
Catalytic Reforming Unit #2 (H-14) (EPN 65)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 2.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.
Sat Gas Stabilizer Reboiler (H-16) (EPN 67)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 2.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.
FCCU Preheater (H-18) (EPN 69)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may use all the heater's existing firing rate capacity that is not currently being used. Phillips 66 is not proposing to increase the firing rate capacity of the heater.
Alky Heater (H-21) (EPN 71)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the process heater's annual actual firing rate to increase by an amount equal to approximately 12.5% of its annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.

Emissions Unit	Existing/ New Unit	Project Impact
Catalytic Reforming Unit #2 (H-23) (EPN 72)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 2.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.
Coker Furnace (H-3901) (EPN 74)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may use all the heater's existing firing rate capacity that is not currently being used. Phillips 66 is not proposing to increase the firing rate capacity of the heater.
No. 4 HDS Recycle Hydrogen Heater (H-8401) (EPN 75)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 7.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.
No. 4 HDS Fractionator Feed Heater (H-8402) (EPN 76)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 7.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.

In addition to the above, a new cooling tower will be installed at the Jupiter Sulphur plant. This cooling tower will replace the existing CT-602 cooling tower. The new cooling tower will be of increased capacity. An addendum to the original application was received on October 23, 2020, to request this change be added to the permit application. **MAQP #2619-39** replaced MAQP #2619-38.

On January 6, 2021, DEQ received from Phillips 66 an MAQP application to change the form of limits on the Vacuum Furnace (H-17) and Large Crude Unit Heater (H-24) regarding emissions of oxides of nitrogen (NO_X). Limits on these heaters were originally in the form of a pound per million British thermal unit basis (lb/MMBtu), 30 day rolling average, determined daily, with a daily F-factor determination required. This form of limit requires daily refinery fuel gas analyses, producing a compliance demonstration burden that Phillips 66 preferred to forego. Phillips 66 proposed to revise the form of these emission limitations to an equivalent limit on a parts per million basis. Doing so required that only the concentration of NO_X and oxygen in the stack be measured.

Specifically, Phillips 66 requested that the 0.030 lb/MMBtu limitation on the H-17 heater be changed to a 30 parts per million by volume limitation on a dry basis (ppmvd), at 0% oxygen, on a 30 day rolling average, determined daily. The 0.040 lb/MMBtu limitation on the H-24 was requested to be changed to a 40 ppmvd at 0% oxygen limitation, determined daily on a 30-day rolling average basis. The request resulted in no increase in allowable emissions. A change in emissions monitoring followed, requiring the ppmvd monitoring requirements of 40 Code of Federal Regulations Part 60, Subpart Ja, which is also applicable to these heaters. These limitations are considered equivalent, as demonstrated by 40 CFR 60 Subpart Ja. **MAQP #2619-40** replaced MAQP #2619-39.

On May 4, 2021, DEQ received from Phillips 66 an MAQP application to reinstate flexible limitations on 4 heaters with respect to emissions of oxides of nitrogen (NO_X). It was requested that the Coker Heater H-3901, the No. 4 Hydrodesulfurization Recycle Hydrogen Heater H-8401, the No. 4 Hydrodesulfurization Fractionator Feed Heater H-8402, and the No. 1 Hydrogen Plant Reformer Heater H-9401 be placed under a bubble limit at 17.22 lb/hr and 75.44 tons per year. The request was incorporated as **MAQP #2619-41**, replacing MAQP #2619-40.

On October 29, 2021, DEQ received an application from Phillips 66 to modify the current MAQP. Phillips 66 identified that a physical change at the facility will increase the maximum hourly gas oil throughput rate for the FCCU. The allowable annual average gas oil throughput rate of the FCCU would remain the same; therefore, no change to the allowable annual emissions from the unit would result. However, an increase in the maximum hourly emissions rates may occur. This affects the original ambient air quality analyses for short term particulate matter impacts reviewed in the issuance of MAQP #2619-39. The current action addresses the change in emissions and associated impacts in the ambient impact analyses section of the permit analysis. The DEQ concludes that this update to the project permitted in MAQP #2619-39 would not change the original determination that it would not cause or contribute to an ambient air quality or ambient increment exceedance.

In addition, numerous permit cleanup items including the shutdown or removal of various emitting units are addressed in this action. These changes are tableized below. **MAQP #2619-42** replaced MAQP #2619-41.

Permit Condition	Proposed Permit Condition Revision
• II. Conditions and Limitations.C.7.f • II. Conditions and Limitations.H.1	Phillips 66 proposes to remove the H-2, H-4, H-5, and H-19 heater entries from the referenced permit conditions because the stacks of these idled heaters are being removed from the site, which will make the heaters effectively inoperable.

Permit Condition	Proposed Permit Condition Revision
• II. Conditions and Limitations.C.7.f • II. Conditions and Limitations.H.1	Phillips 66 proposes to remove the H-15 heater entries from the referenced permit conditions because the idled heater is being removed from the site.
• II. Conditions and Limitations.A.3.d • II. Conditions and Limitations.A.3.f • II. Applicable Rules and Regulations.C.10.e	Phillips 66 proposes to remove Proto Gas Tanks #2901 - #2907 from the referenced permit conditions because the tanks are out of service since the knock engines (engines used to measure gasoline and blending component octane ratings) previously fed by the tanks are no longer used. The knock engines have been replaced by analyzers that do not rely on sample materials from the tanks.
• II. Conditions and Limitations.A.1.f • II. Applicable Rules and Regulations.C.8.g	Phillips 66 proposes to remove the T-36 tank entries from the referenced permit conditions because the tank has been removed from the site.
• II. Conditions and Limitations.A.1.f • II. Conditions and Limitations.A.1.g • II. Conditions and Limitations.C.10 • II. Applicable Rules and Regulations.C.8.g • II. Applicable Rules and Regulations.C.8.h	Phillips 66 proposes to remove the T-3201 tank entries from the referenced permit conditions because the tank has been removed from the site.
• II. Conditions and Limitations.A.1.l • II. Applicable Rules and Regulations.C.8.k	Phillips 66 proposes to remove the Corrugated Plate Interceptor (CPI) separators entries from the referenced permit conditions because the CPI separators have been removed from the site. The replacement API separators were installed at the site as authorized by MAQP No. 2619-32, not MAQP No. 1821-32 as currently referenced.
• II. Conditions and Limitations.C.18	Phillips 66 proposes to remove the referenced permit condition because a de minimis notification was submitted to MT DEQ on October 8, 2021, in which Phillips 66 proposed to place the T-4510 and T-4511 tanks back in service.
• II. Conditions and Limitations.C.7.u.i	Phillips 66 proposes to remove the referenced permit condition because it is duplicative of II. Conditions and Limitations.C.7.p.ii.

Permit Condition	Proposed Permit Condition Revision
• II. Conditions and Limitations.C.7.y	Phillips 66 proposes to remove the referenced permit condition because it is duplicative of II. Conditions and Limitations.C.7.p.i. However, be sure to add an ARM 17.8.752 citation to II. Conditions and Limitations.C.7.p.i. when the referenced permit condition is removed.
• II. Conditions and Limitations.C.7.z	Phillips 66 proposes to remove the referenced permit condition and transfer its emission standards to subparagraphs under II. Conditions and Limitations.C.7.p for the No. 1 H_2 Plant Reformer Heater (H-9401) and II. Conditions and Limitations.C.7.t for the No. 2 H_2 Plant Reformer Heater (H-9701), respectively.
• II. Conditions and Limitations.A.1.m • II. Conditions and Limitations.A.3.g • II. Conditions and Limitations.C.20.b • II. Conditions and Limitations.C.20.c • II. Conditions and Limitations.F.10 • II. Applicable Rules and Regulations.C.8.l • II. Applicable Rules and Regulations.C.10.f	Phillips 66 proposes to revise the "Backup Emergency Generator for the HDS Flare Drum Pump" engine description used in the referenced permit conditions to "Emergency Generator Engine (G-8401) for the HDS Flare Drum Backup Pumps."
• II. Conditions and Limitations.F.14	Phillips 66 proposes to add the following sentence after the second sentence in the permit condition to document EPA Method 2510B is an equivalent method that has been approved by MT DEQ: "Phillips 66 has been approved by the department to utilize EPA Method 2510B to determine conductivity."

On April 20, 2022, DEQ received from Phillips 66, an administrative amendment request to reduce allowable emissions from the Fluid Catalytic Cracking Unit. In review of emissions inventory estimation methodologies, Phillips 66 discovered an error in calculated emissions of oxides of nitrogen (NO_X), and carbon monoxide (CO), from the fluid catalytic cracking unit (FCCU). The emissions were calculated to be higher than actual. Because these previously reported emissions from the FCCU were utilized to calculate net emissions increases for previous project(s), Phillips 66 proposed to reduce allowable future emissions from the FCCU to maintain validity of previous conclusions regarding the project(s).

This permitting action placed a limit on CO emissions from the FCCU at 66.0 tons per year, and NO_X to 59.64 tons per year. The CO limit ensured that allowable emissions of CO from the FCCU did not trigger the requirements of the Prevention of Significant Deterioration program as found in ARM 17.8 subchapter 8. The NO_X limit set the potential to emit using a corrected emissions factor. **MAQP #2619-43** replaced MAQP #2619-42.

On May 13, 2022, DEQ received from Phillips 66 an application triggering the Prevention of Significant Deterioration requirements of ARM 17.8 Subchapter 8 (PSD).

Phillips 66 discovered that an error was made in the calculation of the CO and NO_X emission rates that were reported for the FCCU Stack (EPN 86) in the site's 2018 and 2019 emissions inventories. Those reported emission rates were used as the emissions unit's 2018 and 2019 baseline actual CO and NO_x emission rates in the Billings Projects for 2022 PSD applicability analysis calculations – a project permitted as MAQP #2619-39. However, the corrected 2018 and 2019 CO and NO_x emission rates are lower than the 2018 and 2019 CO and NO_X emission rates that were reported for the emissions unit. Therefore, Phillips 66 is proposing to revise the emissions unit's 2018 and 2019 baseline actual CO and NO_X emission rates used in the project's PSD applicability analysis calculations so that they equal the unit's corrected 2018 and 2019 CO and NO_X emission rates. Also, after further analysis, Phillips 66 proposed to revise the post-project annual potential to emit CO emission rate for the FCCU Stack. In combination, these updates had the following impacts on the project's PSD applicability analysis:

• The project resulted in a significant net emissions increase in CO, thus making the project subject to PSD review for CO; and

• The project continued to result in a significant net emissions increase in NO_X, but the increase will be greater than previously calculated and reviewed.

Therefore, DEQ re-permitted this project, going through PSD for CO, and re-assessed the impacts of increased emissions changes for NO_X. This action did not change the capacities or proposed operation of the units permitted in the Billings Projects for 2022, but the FCCU Stack's allowable emissions of CO and NO_x on an annual basis was increased to allow for operation at the design capacities that Phillips 66 required. **MAQP 2619-44** replaced MAQP #2619-43.

On September 5, 2023, DEQ received from Phillips 66 an application to modify their MAQP based on changes to the refinery under the Vacuum Improvement Project (VIP). VIP included improvements in crude unit distillation capabilities and wastewater treatment facilities, an increase in hydrogen production capabilities, and an expansion of the Jupiter Sulphur, LLC (Jupiter) sulfur recovery facilities at the existing refinery.

With the submittal, Phillips 66 proposed to include two new NO_X and SO_2 emission limitations for two of the affected units affected by the VIP (i.e. Large Crude Unit Heater H-24 and Vacuum Furnace H-17). That submittal kept VIP non-major modification for NO_X and SO_2 under the PSD program.

In addition, Phillips 66 requested the following:

- Revise the SO_2 emission limitation addressed in MAQP #2619-39 for the fluid catalytic cracking unit (FCCU). DEQ did not approve of this change.
- Clarify the SO_2 emission limitation addressed in MAQP #2619-32 for the Jupiter Sulfur Recovery Unit (SRU) Main Stack #2.
- Removal of Compressor C-23 as well as its permit terms and conditions.

- Clarify the applicability of certain new source performance standards (NSPS) to further streamline requirements for refinery operations.

MAQP #2619-45 replaced MAQP #2619-44.

C. Current Permit Action

On May 21, 2025, DEQ received an application from Tetra Tech, on behalf of Phillips 66, to modify their MAQP. This permit application follows previously permitted physical changes to the Fluidized Catalytic Cracking Unit (FCCU) in conjunction with changes in the method of operating the FCCU. The modification requests an increase in throughtput of gas oil to the FCCU from 24,000 barrels per day (bpd) to 26,000 bpd. Phillips 66 also requested the removal of the No. 3 H_2 Plant Reformer Heater and No. 3 H_2 Plant PSA Off-Gas Vent.

The proposed changes addressed by this permit action demonstrate an increase in annual emission rates for PM_{10}, $PM_{2.5}$, SO_2, and VOCs. The proposed emissions increases under the current permit action do not exceed applicable significant emission rates (SER) listed in ARM 17.8.801(28) for any of these pollutants and thus further analysis is not explicitly required. Further, modeling thresholds and major New Source Review, Prevention of Significant Deterioration (PSD) review have previously been triggered for both PM_{10} and $PM_{2.5}$ and Phillips 66 has demonstrated emissions from the proposed project would comply with the national ambient air quality standards (NAAQS) for PM_{10} and $PM_{2.5}$. However, for consistency and clarity, Phillips 66 chose to conduct updated modeling for particulate matter (PM_{10}, $PM_{2.5}$) to supplement and demonstrate ongoing compliance with previously submitted PSD analyses.

MAQP #2619-46 replaces MAQP #2619-45.

D. Response to Public Comments (if received)

Person/Group Commenting	Permit Reference	Comment	DEQ Response

E. Additional Information

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

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the ARM and are available, upon request, from

DEQ. Upon request, DEQ will provide references for locations of complete copies of all applicable rules and regulations or copies where appropriate.

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

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

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of DEQ, provide the facilities and necessary equipment, including instruments and sensing devices, and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by DEQ. Phillips 66 shall also comply with monitoring and testing requirements of this permit.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by DEQ, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., MCA.Phillips 66 shall comply with all requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from DEQ upon request.

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

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

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

1. ARM 17.8.204 Ambient Air Monitoring
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
7. ARM 17.8.221 Ambient Air Quality Standard for Visibility
8. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

Phillips 66 must comply with the applicable ambient air quality standards. See Section V Ambient Air Impact Analysis.

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

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

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, Phillips 66 shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

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

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

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

6. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. (4) Commencing July 1, 1972, no person shall burn liquid or solid fuels containing sulfur in excess of 1 pound of sulfur per million Btu fired. (5) Commencing July 1, 1971, no person shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions. Phillips 66 will burn RFG gas, PSA gas, or natural gas, which will meet this limitation.

7. ARM 17.8.324 Hydrocarbon Emissions--Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except

through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.

8. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR Part 60, NSPS. Phillips 66 is considered an NSPS affected facility under 40 CFR Part 60. Below is a summary of applicability review:

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

   b. Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units shall apply to all affected boilers at the facility which were constructed after June 19, 1984 and are larger than 100 MMBtu/hr. Affected facilities that also meet the applicability requirements under Subpart J or Ja are subject to the PM and NO_X standards under this subpart and the SO_2 standards of Subpart J or Ja. Boilers B-5 and B-6 are subject to this subpart as well as Subpart J.

   c. Subpart J - Standards of Performance for Petroleum Refineries, applies to:
      1. All of the heaters and boilers at the Phillips 66 refinery, as a requirement of a consent decree if not also through the rule itself (except those subject to or electing to comply with Subpart Ja);

      2. The Fluid Catalytic Cracking Unit (FCCU). "Modification" or "reconstruction" of this unit has not occurred, therefore, NSPS J continues to apply as originally set by consent decree and continually required by the MAQP for CO, SO_2, PM and opacity provisions (ARM 17.8.749); and

      3. Any other affected equipment

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

      1. Vacuum Furnace H-17 installed as part of the Vacuum Improvement Project permitted in MAQP 2619-32 (upon startup of H-17).

      2. Large Crude Unit Heater H-24 resulting from the Vacuum Improvement Project permitted in MAQP 2619-32 (upon startup after reconstruction of H-24).

      3. Sulfur Recovery Units. The post-Vacuum Improvement Project sulfur recovery plant permitted in MAQP #2619-32 (SRU No. 1, 2, and 3, including the sulfur pits associated with these units,) became

subject to Subpart Ja as a result of that project. As the PSD analysis associated with the Vacuum Improvement Project relied on all Sulfur Recovery Units being subject to the requirements of NSPS Ja, applicability was also required in overlapping fashion through authority of ARM 17.8.749. In MAQP #2161-39, the installation of equipment that will provide all three SRUs with the capability to operate utilizing oxygen enrichment was proposed; therefore, the units continue to be subject to NSPS Ja, with Equation 1 at 40 CFR 60.102a(f)(1)(i) applicable during such operations.

4. Delayed Coking Unit.

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

6. Refinery Flare (Excess Fuel Gas Flare Header and Releif Flare Header).

7. Any other affected equipment.

e. Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids, applies to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after May 18, 1978, and prior to July 23, 1984, for equipment not overridden by 40 CFR 63, Subpart CC. The affected tanks include, but are not limited to:

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

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

f. Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels, applies to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984, for equipment not overridden by 40 CFR 63, Subpart CC. The affected tanks include, but are not limited to, the following:

Tank ID	Contents
T-35	Slop oil
T-72	Gasoline
T-107*	Residue
T-110	Material with a max true vapor pressure of 11.1 psia
T-0851	(No. 5 HDS Feed Storage Tank)

T-1102 (Crude Oil Storage Tank)
T-2909 Gasoline – Low Sulfur

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

g. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, applies to the cryogenic unit, C3901 Coker Unit Wet Gas Compressor; C-5301 Flare Gas Recovery Unit Liquid Ring Compressor; C-5302 Flare Gas Recovery unit Liquid Ring Compressor; C-8301 Cryo Unit Inlet Gas Compressor; C-8302 Cryo Unit Refrigerant Compressor; C-8303 Cryo unit Regeneration Gas Compressor; C-26 FCCU Wet Gas Compressor, and any other applicable equipment constructed or modified after November 7, 2006.

The C-8401 No. 4 HDS Makeup/Recycle Hydrogen Compressor, C-7401 Hydrogen Makeup/Reformer Hydrogen Compressor, C-9401 Hydrogen Plant Feed Gas Compressor, C-9501 Makeup/Recycle Gas Compressor, and C-9701 Feed Gas Compressor are in hydrogen service.

h. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, applies to the C-8402 Makeup/Recycle Hydrogen Compressor and No. 4 HDS Makeup/Recycle Compressor which are in hydrogen service, as well as any other applicable equipment constructed, reconstructed, or modified after November 7, 2006 including the following:

1) Delayed coker unit

2) Cryogenic unit

3) Hydrogen membrane unit

4) Gasoline merox unit

5) Crude Units

6) Gas oil hydrotreater unit (consisting of a reaction section, fractionation section, and an amine treating section)

7) No. 1 H_2 Unit (22.0-million standard cubic feet per day (MMscfd) hydrogen plant feed system)

8) Alkylation Unit Butane Defluorinator Project (consisting of heat exchangers; X-453, X-223, X-450, X-451, X-452, pumps; P-646, Vessels; D-130, D-359, D-360)

9) Alkylation Unit Depropanizer Project

10) #3 Sour Water Stripper (SWS) Unit

11) Fugitive components associated with boilers #B-5 and #B-6

12) The fugitive components associated with the No.2 H_2 Unit and the No.5 HDS Unit

13) HPU

14) FCCU

15) PB Merox Unit

i. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems applies to the coker unit drain system, desalter wastewater break tanks, gas oil hydrotreater, No.1 Hydrogen Unit (20.0-MMscfd hydrogen plant), C-23 compressor station, Alkylation Unit Butane Defluorinator Project, Alkylation Unit Depropanizer Project, the individual drain system in the No.2 H_2 Unit, the individual drain system in the No 3 H_2 Unit, the aggregate facility of the Vacuum Unit including the main oily wastewater sump through and including the two new parallel API OWSs and Tank T-164 as proposed in MAQP 2619-32 and the No. 5 HDS Unit, Tank T-4523, and any other applicable equipment, for equipment not overridden by 40 CFR 63 Subpart CC.

j. Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines applies to the diesel fired engines used for operation of the Backup Coke Crusher, the Backup Firepump Engine, and the Emergency Generator Engine (G-8401) for the HDS Flare Drum Pumps and any other applicable engines

k. All other applicable subparts and referenced test methods.

9. <u>ARM 17.8.341 Emission Standards for Hazardous Air Pollutants</u>. Phillips 66 shall comply with the standards and provisions of 40 CFR Part 61, as listed below:

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

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

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

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

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

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

      The FCCU will not undergo "reconstruction" due to the modifications as described for MAQP #2619-39 and therefore will continue to be subject to the existing FCCU provisions.

      SRU #2 will have modifications as described in MAQP #2619-39, which will cost greater than 50% of the fixed capital cost for a comparable new unit. As such, SRU #2 will become subject to the new SRU provisions.

   d. Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, applies to the diesel-fired engine used for operation of the Backup Coke Crusher, the Cryo Backup Air Compressor engine, the Boiler House Air Compressor engine, the Pump for Storm Water to Holding Pond engine, the Backup Firepump Engine, the Emergency Generator Engine (G-8401) for the HDS Flare Drum Pumps, the Boiler House Backup Air Compressor engine, and any other applicable engines.

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

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

2. ARM 17.8.402 Requirements. Phillips 66 must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP).

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

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an

applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to DEQ. The current permitting action is re-permitting a major modification of a major stationary source, and as such, a fee of $3,500 was required. DEQ received the appropriate fee on May 17, 2022.

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

   An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The DEQ may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

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

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

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify or use any air contaminant sources that have the PTE greater than 25 tons per year of any pollutant. Phillips 66 has the PTE greater than 25 tons per year of PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, and SO_2; therefore, an air quality permit is required.

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

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

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, modification, or use of a source. Phillips 66 submitted the appropriate application for this action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of

general circulation in the area affected by the application for a permit. Phillips 66 made public notice of the application in the *Billings Gazette* on May 15, 2025.

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

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

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

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving Phillips 66 of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

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

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

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

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as

a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with

ARM 17.8.748, ARM 17.8.749, ARM 178.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

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

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

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

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

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications --Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.

   Phillips 66's existing petroleum refinery in Billings is defined as a "major stationary source" because it is a listed source with the PTE more than 100 tons per year of several pollutants (PM, PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, and VOCs).

   The current permitting action is revisiting a previously permitted major modification of a major stationary source (MAQP #2619-39 for Billings Projects for 2022). The project requires additional PSD review for CO due to a correction of an error which revealed that there is a significant net increase in CO associated with it. NO_x emissions were subject to PSD review during the initial major source permitting; however, this action increased the allowable levels of NO_x associated with that project and therefore included a PSD review at the higher allowable NO_x levels.

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

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

   The Phillips 66 Company Billings refinery is located in an area designated as attainment/unclassifiable for all pollutants. The nearest non-attainment area is in Laurel, an SO_2 nonattainment area centered around the CHS refinery. The current project does not pose a significant emissions increase of SO_2.

I. ARM 17.8, Subchapter 12 - Operating Permit Program Applicability:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any stationary source having:

   a. PTE > 100 TPY of any pollutant;

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

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

2. ARM 17.8.1204 Air Quality Operating Permit Program Applicability. (1) Title V of the FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204 (1), obtain a Title V Operating Permit. In reviewing and issuing MAQP #2619-46 for Phillips 66, the following conclusions were made:

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

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

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

   d. This facility is subject to NSPS requirements.

   e. This facility is subject to NESHAP requirements.

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

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

Based on these facts, DEQ determined that Phillips 66 is subject to the Title V operating permit program.

III. BACT Determination

A BACT determination is required for each new or modified source. P66 shall install on the new or modified source the maximum air pollution control capability which is technically practicable and economically feasible, except that BACT shall be utilized.

A BACT determinaiotn was not required for the current permit action because the FCCU is not undergoing any physical changes and is not a new or modified sourcer pursuant to ARM 17.8.752(1). Prior BACT analyses addressed the FCCU physical changes in September 23, 2020, and October 29, 2021, MAQP Applications for NO_X, CO, SO_2, and GHG as CO_2e.

IV. Emission Inventory

Overall Refinery Emissions

Reevaluation of MAQP 2619-39 Project Emissions - Updated for 26,000 bpd Annual Average								
Source	Estimated Project Emissions (tpy)							
	CO	NOx	SO_2	PM (filt)	PM_{10}	$PM_{2.5}$	VOC	CO_{2e}
Project only or net emissions increase (whichever is higher) Sept_2020 App[1]	227.43	94.79	36.83	19.4	33.88	33.22	22.75	243,782
FCCU @ 24,000 bpd (baseline)	133.80	72.09	26.32	53.22	47.35	47.35	0.00	237,706
FCCU @ 26,000 bpd	144.96	78.10	28.52	57.65	51.29	51.29	0.00	257,515
Downstream impacts - Tanks							6.70	
No. 3 H_2 Plant Reformer Heater	-14.98	-17.48	-0.13	-0.59	-1.53	-1.05	-1.23	-111,795
No. 3 H_2 Plant PSA Off-Gas Vent	-26.82	0	0	0	0	0	0	-160
Change in emissions[2]	-30.64	-11.47	2.06	3.84	2.42	2.90	5.47	-92,146
PSD Applicability Emissions[3]	196.79	83.32	38.89	23.24	36.30	36.12	28.22	151,636
PSD Significance Threshold	100	40	40	25	15	10	40	75,000
Change?	Already PSD	Already PSD	N/A	N/A	Already PSD	Already PSD	N/A	Already PSD

Project Specific Emissions

Pollutant	Project-Only Emissions Increase (tpy)	Project-Only Emissions Decrease (tpy)	PSD Significant Threshold (tpy)	PSD Significant? (Yes/No)
CO	11.16	-41.80	100	Yes, already PSD
NOx	6.01	-17.48	40	Yes, already PSD
PM	4.43	-0.59	25	N/A
PM_{10}	3.94	-1.53	15	Yes, already PSD
$PM_{2.5}$	3.94	-1.05	10	Yes, already PSD
SO_2	2.81	-0.13	40	N/A
VOC	0.00	-1.23	40	N/A

V. Existing Air Quality

Phillips 66 is located at 401 South 23rd Street in Billings, Montana in the NW ¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County. The area is currently designated as attainment/unclassifiable for all National Ambient Air Quality Standards (NAAQS).

VI. Air Quality Impacts Analyses

Tetra Tech conducted air quality modeling to address proposed changes to emitting units previously permitted as a part of Phillips 66's "Billings Projects for 2022". This ambient air impact analysis and analyses submitted with previous permit actions were conducted pursuant to the requirements of ARM 17.8.820 and ARM 17.8.822 to demonstrate that the proposed modification would not cause or contribute to a violation of any NAAQS, MAAQS or applicable PSD increment (PSD Class II Air Quality Analysis); pursuant to ARM 17.8.825, and ARM 17.8.1106 to show that the project does not cause or contribute to any adverse impact on visibility within any federal Class I areas (PSD Class I Air Quality Analysis and PSD Class I Area Impact Analysis); and pursuant to ARM 17.8.824 to show that the project does not cause or contribute to additional impacts to soils, vegetation, and growth (Additional Impact Analysis).

The changes addressed in this permit action demonstrate an increase in annual emission rates for PM_{10}, $PM_{2.5}$, SO_2, and VOCs. The emission increases do not exceed the significant emission rates listed in ARM 17.8.801(28) for PM_{10}, $PM_{2.5}$, SO_2, and VOCs and thus do not explicitly warrant further analyses. However, modeling thresholds and PSD review have previously been triggered for both PM_{10} and $PM_{2.5}$, and Phillips 66 demonstrated in past permit actions that the project would comply with PM_{10} and $PM_{2.5}$ standards. For the sake of consistency and clarity, Phillips 66 chose to conduct updated modeling for particulate matter to supplement previously submitted PSD analyses.

Emission increases were first modeled to determine if any model receptors exceeded the Significant Impact Levels (SILs), presented in Table VI-1. For those pollutant and averaging times that exceed the applicable SILs, Phillips 66 was required to demonstrate compliance with the applicable NAAQS, MAAQS, and PSD Increments, also presented in Table VI-1. For this project, $PM_{2.5}$ annual Class II SILs were exceeded, which then required NAAQS and Class II Increment analyses for applicable pollutant/time periods.

Table VI-1 Applicable Standards

Pollutant	Averaging Period	Class I SIL (µg/m^3)	Class II SIL (µg/m^3)	Primary NAAQS (µg/m^3)	MAAQS (µg/m^3)	Class I Increment (µg/m^3)	Class II Increment (µg/m^3)	SMC (µg/m^3)
PM_{10}	Annual	0.2	1	-	50	4	17	-
$PM_{2.5}$	Annual	0.03	0.13	9	-	1	4	-

The SIL, Increment, and MAAQS/NAAQS compliance demonstrations were conducted using the latest available version of EPA-approved American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) and associated preprocessors. Specifically:

- AERMOD version 24142: Air dispersion model.
- AERMET version 19191: processes NWS meteorological data for input to AERMOD.
- AERMINUTE version 15272: processes 1-minute NWS wind data to generate hourly average winds for input to AERMET.
- AERSURFACE version 13016: processes 1992 National Land Cover Data surface characteristics for input to AERMET.
- AERMAP version 18081: Processes National Elevation Data from the USGS to determine elevation of sources and receptors for input into AERMOD.
- BPIPPRM version 04274: characterizes building downwash for input to AERMOD.

Regulatory default options were used for all model runs. Rural dispersion coefficients were applied, as all of Montana currently meets this criterion. All buildings at the site were evaluated for building downwash on each modeled point source, using BPIPPRM.

Five years of metrological data (2015-2019) ready for use in AERMOD was constructed using representative surface and upper air data. Surface air data was obtained from the closest National Weather Service (NWS) station, which is located approximately 4 km to the north-northwest of the project site, at the Billings Logan International Airport (KBIL – WMO 726770, WBAN 24033). This NWS station also provided the automated surface observing system (ASOS) one-minute data used with AERMINUTE. The Great Falls Upper Air station (WMO 72776, WBAN 04102) was used for upper air data. The ADJ_U* option was employed in AERMET to account for stable, low wind speeds.

A series of three nested receptor grids were used in the model to calculate the ambient air impacts around the project location. Discrete receptors were placed at 10 m spacing along the site's fence line, 25 m spacing from the site to 1.5 km from the site, 50 m spacing from 1.5 km to 3 km from the site, and 200 m spacing from 3 km to 10 km from the site, totaling 8590 receptor locations. Only the significantly impacted receptors (receptors with modeled concentrations equal to or greater than their respective SILs) were used for the NAAQS/MAAQS and applicable Increment analyses.

The source and building elevations at the site were based on the existing graded elevation. Receptor elevations and regional inventory source elevations were determined using the terrain preprocessor AERMAP and elevation data based on 1/3 arc-second (approximately 10 m resolution) National Elevation Dataset (NED) from the United States Geological Survey (USGS).

The following PM_{10} and $PM_{2.5}$ monitoring sites were identified for use as background concentrations. The PM_{10} data was measured at the Birney – Tongue River monitor (AQS ID: 30-087-0001) from 2018 to 2020, which is the latest available complete dataset from that monitor before it ceased operating in October 2021. The Birney – Tongue River site is the nearest monitor with a recent complete PM_{10} dataset, and despite the smaller population of Birney compared to Billings, the monitor's location next to a roadway makes it a conservative choice for calculating background PM_{10} concentrations.

$PM_{2.5}$ data was measured at the Billings – Lockwood monitor (AQS ID: 30-111-0087) during the most recent complete data period from 2022 to 2024. The monitor is located immediately downwind from the Phillips 66 facility, which adds a degree of conservatism to the $PM_{2.5}$ background concentration estimation. The background concentrations from both monitors were calculated both including and excluding atypical events (i.e., wildfires) to illustrate the impacts of wildfires on background concentrations, and the final values are displayed in Table VI-2. Data with atypical events removed was used for all purposes in this analysis. The background concentrations are added to the modeled concentrations in the NAAQS analysis.

Table VI-2 Background Concentrations

Pollutant	Averaging Time	Background Conc. ($\mu g/m^3$)(1)	Background Conc. ($\mu g/m^3$)(2)	Basis	Site
PM_{10}	Annual	15.0	12.6	3-year Annual avg.	Birney – Tongue River (30-087-0001)(3)
$PM_{2.5}$	Annual	6.7	5.6	3-year Annual avg.	Billings – Lockwood (30-111-0087)(4)

(1)Data includes atypical event data in the calculations.
(2)Data excludes atypical event data in the calculations.
(3)Data years 2018-2020 used for annual average calculation.
(4)Data years 2022-2024 used for annual average calculation.

Secondary $PM_{2.5}$ impacts consisting primarily of NO_x and SO_2 precursor emissions due to the project cannot be evaluated with the AERMOD dispersion model since it cannot take chemical transformations into account. Phillips 66 assessed secondary $PM_{2.5}$ formation using hypothetical source precursor pollutant (NO_x and SO_2) emission rate data and secondary $PM_{2.5}$ photochemical modeling results that were utilized by the EPA to develop Modeled Emission Rates for Precursors (MERPs) for NO_x and SO_2. Photochemical modeling results for the appropriate hypothetical source's three emission rates and a linear fit was used to determine the $PM_{2.5}$ impacts for both 24-hour and annual emission increases of NO_x and SO_2. These impacts were added to all $PM_{2.5}$ AERMOD modeling results, as displayed in the applicable tables below.

Source parameters were provided by Phillips 66. All parameters were "point" sources in AERMOD, and their descriptions are displayed in Table VI-3. Three separate scenarios were run for Jupiter's two stacks: average elemental sulfur/average ATS production mode ("NORM"), maximum elemental sulfur production mode ("Max S"), and maximum ATS production mode ("Max ATS"). The differences of these three modes are reflected in the stack velocity and temperature; the emissions in all three scenarios are the same.

Table VI-3 Onsite Source Descriptions

Source ID	Source Description	Source Category
P_3	Loading Rack VCU	Other Existing Source
P_51_54	Boiler House (B-1, B-2, B-5, & B-6) Stack	Other Existing Source
P_55	Temporary Boiler	Other Existing Source
P_56	Small Crude Unit Heater (H-1)	NOx: Contemporaneous Source; PM2.5: Other Existing Source
P_61	No. 2 HDS Heater (H-10)	Other Existing Source
P_62	No. 2 HDS Debutanizer Reboiler (H-11)	Other Existing Source
P_63	No. 2 HDS Main Fractionator Reboiler (H-12)	Other Existing Source
P_64	Catalytic Reforming Unit #2 (H-13)	Project-Impacted Source
P_65	Catalytic Reforming Unit #2 (H-14)	Project-Impacted Source
P_67	Sat Gas Stabilizer Reboiler (H-16)	Project-Impacted Source
P_68NEW	Vacuum Furnace (H-17) - NEW	NOx: Contemporaneous Source; PM2.5: Other Existing Source
P_68OLD	Vacuum Furnace (H-17) - OLD	CO and NOx Only Contemporaneous Source
P_69	FCCU Preheater (H-18)	NOx: Project-Impacted Source and Contemporaneous Source; PM2.5: Project-Impacted Source
P_70	Butamer Heater (H-20)	Other Existing Source
P_71	Alky Heater (H-21)	Project-Impacted Source
P_72	Catalytic Reforming Unit #2 (H-23)	Project-Impacted Source
P_73	Large Crude Unit Heater (H-24)	NOx: Contemporaneous Source; PM2.5: Other Existing Source
P_74	Coker Furnace (H-3901)	Project-Impacted Source
P_75	No. 4 HDS Recycle Hydrogen Heater (H-8401)	NOx: Project-Impacted Source and Contemporaneous Source; PM2.5: Project-Impacted Source
P_76	No. 4 HDS Fractionator Feed Heater (H-8402)	NOx: Project-Impacted Source and Contemporaneous Source; PM2.5: Project-Impacted Source
P_77	No. 1 H2 Plant Reformer Heater (H-9401)	NOx: Contemporaneous Source; PM2.5: Other Existing Source
P_78	No. 5 HDS Charge Heater (H-9501)	NOx: Project-Impacted Source and Contemporaneous Source;

Source ID	Source Description	Source Category
		PM2.5: Project-Impacted Source
P_79	No. 5 HDS Stabilizer Reboiler Heater (H-9502)	NOx: Project-Impacted Source and Contemporaneous Source; PM2.5: Project-Impacted Source
P_80	No. 2 H2 Plant Reformer Heater (H-9701)	NOx: Contemporaneous Source; PM2.5: Other Existing Source
P_81	Flare	Other Existing Source
P_82	Jupiter Flare	Other Existing Source
P_83_A	Jupiter Main Stack No. 1 - Average	NOx: Modified Source and Contemporaneous Source; PM2.5: Modified Source
P_83_S	Jupiter Main Stack No. 1 - Max S	NOx: Modified Source and Contemporaneous Source; PM2.5: Modified Source
P_83_T	Jupiter Main Stack No. 1 - Max ATS	NOx: Modified Source and Contemporaneous Source; PM2.5: Modified Source
P_85_A	Jupiter Main Stack No. 2 - Average	NOx: Modified Source and Contemporaneous Source; PM2.5: Modified Source
P_85_S	Jupiter Main Stack No. 2 - Max S	NOx: Modified Source and Contemporaneous Source; PM2.5: Modified Source
P_85_T	Jupiter Main Stack No. 2 - Max ATS	NOx: Modified Source and Contemporaneous Source; PM2.5: Modified Source
P_86	FCCU Stack	NOx: Modified Source and Contemporaneous Source; PM2.5: Modified Source
P_87	Cooling Tower - Combination Unit	Other Existing Source
P_88	Cooling Tower - Condensate Unit	Other Existing Source
P_89	Cooling Tower (CWT-5)	Other Existing Source
P_90	Jupiter Cooling Tower (CT-615A/B/C)	Other Existing Source
P_91	Jupiter Cooling Tower (CT-120)	Other Existing Source
P_92	Jupiter Cooling Tower (CT-602)	Shutdown Source
P_141_1	Coke Handling	Project-Impacted Source
P_141_2	Delayed Coking Unit - Vent, Coke Cutting, and Water Handling	Project-Impacted Source
P_143_1	Backup Coke Crusher Diesel Engine	Other Existing Source
P_143_2	Boiler House Backup Air Compressor Engine	NOx: Contemporaneous Source; PM2.5: Other Existing Source
P_143_3	Coker Backup Air Compressor Engine	NOx: Contemporaneous Source; PM2.5: Other Existing Source
P_143_4	HDS Flare Drum Backup Pumps	NOx: Contemporaneous Source;

Source ID	Source Description	Source Category
	Generator Engine (G-8401)	PM2.5: Other Existing Source
P_143_5	P400 E Diesel Firewater Pump at Ponds	Other Existing Source
P_143_6	P491 Cooling Tower Water to Fire Water	Other Existing Source
P_143_7	P4701 W Diesel Firewater Pump at Ponds	Other Existing Source
P_143_8	Boilerhouse Emergency Diesel Generator	Other Existing Source
P_143_9	MCC7 Emergency Diesel Generator	Other Existing Source
P_143_10	P510 Storm Water Sump to Holding Pond	Other Existing Source
P_143_11	Blender Research Octane Knock Engine	Other Existing Source
P_143_12	Blender Motor Octane Knock Engine	Other Existing Source
P_143_13	Main Lab Research Octane Knock Engine	Other Existing Source
P_143_14	Main Lab Motor Octane Knock Engine	Other Existing Source
P_164	No. 3 H2 Plant Reformer Heater	Removed / Not Constructed
P_165	New Jupiter Cooling Tower	New Source

PSD Class II Air Quality Analysis

PM_{10} and $PM_{2.5}$ emissions increases at the project site were modeled and compared to applicable SILs. The annual emissions increases are provided in Table VI-4. New sources were given their potential to emit emission rate, modified sources were given actual-to-potential emission rates, shutdown sources negative emissions, project impacted sources and contemporaneous sources were given incremental emission rate increase or actual-to-potential emissions increases, as applicable. These model runs also determined which of the three operating scenarios for the Jupiter stacks created the highest impacts, and those scenarios were retained for further cumulative analyses, as applicable.

Table VI-4 SIL Modeled Emissions Increases

Source ID	PM_{10} Annual (tpy)	$PM_{2.5}$ Annual (tpy)
P_56	0.000	0.000
P_64	0.014	0.010
P_65	0.006	0.004
P_67	0.015	0.010
P_68OLD	0.000	0.000
P_68NEW	0.000	0.000
P_69	0.150	0.100
P_71	0.100	0.070
P_72	0.015	0.010
P_73	0.000	0.000
P_74	0.095	0.066
P_75	0.031	0.022
P_76	0.032	0.022
P_77	0.000	0.000

Source ID	PM_{10} Annual (tpy)	$PM_{2.5}$ Annual (tpy)
P_78	0.017	0.012
P_79	0.033	0.023
P_80	0.000	0.000
P_83(1)	13.990	13.990
P_85(1)	13.990	13.990
P_86	3.939	3.939
P_92	-0.033	-0.033
P_141_1	0.049	0.022
P_141_2	0.039	0.039
P_143_2	0.000	0.000
P_143_3	0.000	0.000
P_143_4	0.000	0.000
P_164	0.000	0.000
P_165	0.270	0.270
Total:	**32.751**	**32.565**

(1)For PM_{10} and $PM_{2.5}$ annual, "NORM" produced the highest impacts.

Modeled PM_{10} and $PM_{2.5}$ Class II SIL results are presented in Table VI-5. $PM_{2.5}$ impacts exceeded the Annual SILs, therefore NAAQS and Class II Increment analyses were performed. For the pollutants exceeding the SIL, the significant impact area (SIA) was determined, which represents the furthest distance of the modeled SIL-exceeded receptor from the source. The SIA generally informs the area that should be considered to include offsite sources in the cumulative NAAQS modeling analysis.

Table VI-5 Class II Significant Impact Analysis Results

Pollutant	Avg. Period	Model Conc. (µg/m³)	Secondary Impact Conc. (µg/m³)	Total Conc. (µg/m³)	SIL (µg/m³)	SIA (km)
PM_{10}	Annual	0.252(1)	NA	0.252	1.0	NA
$PM_{2.5}$	Annual	0.243(2)	0.00007	0.243	0.13	2.34

(1)Receptor with the maximum annual concentration in the 5-year period.

(2)Receptor with the maximum annual concentration averaged across 5 years.

<u>NAAQS/MAAQS Air Quality Analysis</u>

For NAAQS and Increment analyses, offsite source emissions within the SIA were included. Additionally, sources located outside of the SIA were screened for potential exclusion based on the "20D" procedure. Sources outside the SIA were excluded if the facility-wide emissions (tons per year, 2018 and 2019 actual averages) are less than 20 times the distance (km) from the facility to the nearest edge of the SIA for annual averaging periods.

Tetra Tech performed this analysis with emissions data provided by MT DEQ, which resulted in the inclusion of several sources. For $PM_{2.5}$, it was determined that the inclusion of the relatively fewer offsite source emissions was sufficient (2.34 km SIA for the annual period), as the location of the Lockwood $PM_{2.5}$ background monitor captures influences from any excluded sources, due to the dominant wind direction from the southwest. The offsite source descriptions are shown in Table VI-6.

Table VI-6 Offsite Source Descriptions

Source ID	Source Description
OFFSTE1	EXXONMOBIL BILLINGS REFINERY - COKER/CO BOILER
OFFSTE2	EXXONMOBIL BILLINGS REFINERY - F-10 COKER FEED
OFFSTE3	EXXONMOBIL BILLINGS REFINERY - F-1201 CATALYTIC HYDROFINING UNIT
OFFSTE4	EXXONMOBIL BILLINGS REFINERY - F-2 CRUDE/VAC UNIT
OFFSTE5	EXXONMOBIL BILLINGS REFINERY - F-201 HYDROFINER
OFFSTE6	EXXONMOBIL BILLINGS REFINERY - F-3 CRUDE UNIT
OFFSTE7	EXXONMOBIL BILLINGS REFINERY - F-3X HYDROFINER
OFFSTE8	EXXONMOBIL BILLINGS REFINERY - F-402 ALKYLATION UNIT
OFFSTE9	EXXONMOBIL BILLINGS REFINERY - F-5 HYDROFINER
OFFSTE10	EXXONMOBIL BILLINGS REFINERY - F-551 HYDROGEN PLANT
OFFSTE11	EXXONMOBIL BILLINGS REFINERY - F-651 HYDROCRACKER
OFFSTE12	EXXONMOBIL BILLINGS REFINERY - F-700 POWERFORMER
OFFSTE13	EXXONMOBIL BILLINGS REFINERY - FCC/CO BOILER
OFFSTE14	EXXONMOBIL BILLINGS REFINERY - FLARE
OFFSTE15	EXXONMOBIL BILLINGS REFINERY - FUGITIVE VOC EMISSIONS
OFFSTE16	EXXONMOBIL BILLINGS REFINERY - INSIGNIFICANT SOURCES
OFFSTE17	EXXONMOBIL BILLINGS REFINERY - SE14: 600HP DIESEL BACKUP ENGINE
OFFSTE18	EXXONMOBIL BILLINGS REFINERY - STANDBY BOILER HOUSE
OFFSTE19	MONTANA SULPHUR & CHEMICAL - 17MM BTU/HR BOILER
OFFSTE20	MONTANA SULPHUR & CHEMICAL - CLAUS PLANTS
OFFSTE21	MONTANA SULPHUR & CHEMICAL - CLEAVER BROOKS BOILER
OFFSTE22	YELLOWSTONE POWER PLANT - CFB BOILERS
OFFSTE23	WESTERN SUGAR COOPERATIVE - BOILER #1 (ERIE CITY)
OFFSTE24	WESTERN SUGAR COOPERATIVE - BOILER #2, 3, 4 (RILEY COAL)
OFFSTE25	WESTERN SUGAR COOPERATIVE - EAST PULP DRYER
OFFSTE26	WESTERN SUGAR COOPERATIVE - WEST PULP DRYER
OFFSTE27	BILLINGS BAKERY - BOILER #1 - NAT GAS FIRED CLEAVER BROOKS BOILER CB-200-150
OFFSTE28	BILLINGS BAKERY - BOILER #2 - NAT GAS FIRED CLEAVER BROOKS BOILER CB-200-150
OFFSTE29	BILLINGS BAKERY - BREAD OVEN BURNER - NATURAL GAS FIRED
OFFSTE30	BILLINGS BAKERY - ROLL OVEN BURNER - NATURAL GAS FIRED

Source ID	Source Description
OFFSTE31	CREMATION & FUNERAL GALLERY - B AND L CREMATION - 1996
OFFSTE32	CITY OF BILLINGS ANIMAL SHELTER - CREMATORIUM
OFFSTE33	A TREASURED FRIEND CREMATORY AND MONUMENT COMPANY - CREMATORIUM
OFFSTE34	WASTEWATER PLANT - AMERICAN STANDARD
OFFSTE35	WASTEWATER PLANT - BURNHAM BOILER
OFFSTE36	WASTEWATER PLANT - CLEAVER BROOKS
OFFSTE37	WASTEWATER PLANT - CUMMINS GENERATOR
OFFSTE38	WASTEWATER PLANT - EMERGENCY BACK-UP GENERATOR
OFFSTE39	WASTEWATER PLANT - FLARE
OFFSTE41	DAHL FUNERAL CHAPEL BILLINGS INC - CREMATORIUM
OFFSTE42	YELLOWSTONE VALLEY VETERINARY INC - ANIMAL CREMATORY #1
OFFSTE43	BILLINGS LANDFILL GAS PRODUCTION FACILITY - FLARE
OFFSTE44	BILLINGS LANDFILL GAS PRODUCTION FACILITY - LANDFILL GAS ENGINE #1
OFFSTE45	BILLINGS LANDFILL GAS PRODUCTION FACILITY - TO FLARE
OFFSTE46	HEIGHTS FAMILY FUNERAL HOME AND CREMATORY - CREMATORIUM
OFFSTE47	BEST FRIENDS ANIMAL HOSPITAL - CREMATORIUMS - ANIMAL AND/OR HUMAN
OFFSTE48	LAUREL EAST VETERINARY SERVICE - SHENANDOAH INCINERATOR
OFFSTE49	WESTERN EMULSIONS PLANT - HOT OIL HEATER
OFFSTE50	MHP - BILLINGS OFFICE - FIRELAKE MODEL P156-SC4
WSC_B5	WESTERN SUGAR COOPERATIVE - BOILER #5 - NATRL GAS
WSC_BF	Western Sugar - BEET UNLOAD/HANDLE FUGTVS
WSC_CLF	Western Sugar - COAL UNLOAD/HANDLE FUGTVS
WSC_KC	Western Sugar - KILN LIMESTONE/COKE TRANSFER
WSC_LF	Western Sugar - LIMESTONE UNLOAD/HNDL FUG
WSC_PC	Western Sugar - PELLETIZER-COOLER
WSC_WE	Western Sugar - EXPOSED AREA - WIND EROSN

New, modified, project-impacted, and contemporaneous sources used potential to emit emission rates; other existing sources (including offsite) were given actual emissions appropriate to each averaging period, averaged over 2018 and 2019.

Offsite emissions averaged over the 2018 to 2019 period were reused in this analysis for the sake of consistency with the previous $PM_{2.5}$ annual NAAQS modeling demonstrations. It should be noted that 2023-2024 emission inventory data was compared to 2018-2019 data, showing that offsite $PM_{2.5}$ emissions were greater over the 2018-2019 period. Therefore, the use of older emission inventory data is not only consistent but also more conservative. These emissions rates are displayed in Table VI-7.

Table VI-7 Modeled Emissions for NAAQS Analysis

Source ID	$PM_{2.5}$ Annual (tpy)
P_3	0.000
P_51_54	7.740
P_55	0.000
P_56	0.310
P_61	0.190
P_62	0.350
P_63	0.690
P_64	0.400
P_65	0.150
P_67	0.410
P_68NEW	0.550
P_69	0.710
P_70	0.020
P_71	0.560
P_72	0.410
P_73	0.900
P_74	1.150
P_75	0.290
P_76	0.290
P_77	2.380
P_78	0.230
P_79	0.450
P_80	1.450
P_81	0.001
P_82	0.001
P_83(1)	17.520
P_85(1)	17.520
P_86	51.296
P_87	6.880
P_88	4.770
P_89	0.390
P_90	0.410
P_91	0.610
P_92	0.000
P_141_1	0.220
P_141_2	0.120
P_143_1	0.010
P_143_2	0.002
P_143_3	0.002

Source ID	$PM_{2.5}$ Annual (tpy)
P_143_4	0.050
P_143_5	0.004
P_143_6	0.015
P_143_7	0.003
P_143_8	0.005
P_143_9	0.001
P_143_10	0.002
P_143_11	0.020
P_143_12	0.020
P_143_13	0.020
P_143_14	0.020
P_164	0.000
P_165	0.270
OFFSTE1	0.000
OFFSTE2	0.000
OFFSTE3	0.000
OFFSTE4	0.000
OFFSTE5	0.000
OFFSTE6	0.000
OFFSTE7	0.000
OFFSTE8	0.000
OFFSTE9	0.000
OFFSTE10	0.000
OFFSTE11	0.000
OFFSTE12	0.000
OFFSTE13	0.000
OFFSTE14	0.000
OFFSTE15	0.000
OFFSTE16	0.000
OFFSTE17	0.000
OFFSTE18	0.000
OFFSTE19	0.000
OFFSTE20	0.000
OFFSTE21	0.000
OFFSTE22	0.000
OFFSTE27	0.000
OFFSTE28	0.000
OFFSTE29	0.000
OFFSTE30	0.000
OFFSTE31	0.000

Source ID	$PM_{2.5}$ Annual (tpy)
OFFSTE32	0.000
OFFSTE33	0.000
OFFSTE34	0.000
OFFSTE35	0.000
OFFSTE36	0.000
OFFSTE37	0.000
OFFSTE38	0.000
OFFSTE39	0.000
OFFSTE41	0.000
OFFSTE42	0.000
OFFSTE43	0.000
OFFSTE44	0.000
OFFSTE45	0.000
OFFSTE46	0.000
OFFSTE47	0.000
OFFSTE48	0.000
OFFSTE49	0.000
OFFSTE50	0.000
OFFSTE23	0.570
OFFSTE24	6.404
OFFSTE25	1.040
OFFSTE26	0.238
WSC_PC	0.174
WSC_BF	0.958
WSC_CLF	0.000
WSC_WE	1.000
WSC_KC	0.575
WSC_LF	0.628
Total:	**131.398**

(1)For $PM_{2.5}$ annual, "NORM" produced the highest impacts.

The results of the NAAQS analysis are shown in Table VI-8, which show that the modeled emissions comply with the $PM_{2.5}$ NAAQS standard.

Table VI-8 NAAQS Analysis Results

Pollutant	Avg. Period	Model Design Value (µg/m^3)	Secondary Impact Conc. (µg/m^3)	Monitor Design Value (µg/m^3)	Total Conc. (µg/m^3)	Primary NAAQS (µg/m^3)	% of NAAQS
$PM_{2.5}$	Annual	0.58[1]	0.00007	5.6	6.18	9.0	69%

(1)Receptor with the maximum annual concentration averaged across 5 years.

PSD Class II Increment Air Quality Analysis

A PSD increment analysis was conducted to demonstrate compliance with the $PM_{2.5}$ PSD Class II increment, as specified in ARM 17.8.804. The major source baseline date for $PM_{2.5}$, as specified in ARM 17.8.801(21), is October 20, 2010. The minor source baseline date is the earliest date after the trigger date (October 20, 2011) on which a major stationary source submits a complete PSD application; in this case September 16, 2015.

For the site's new, modified, project-impacted, and contemporaneous sources, emissions were calculated by subtracting a baseline emission rate of zero from its potential to emit emission rate. For the site's existing $PM_{2.5}$ sources, the source's emission rate change was calculated by subtracting a baseline emission rate equal to the average of its 2013 and 2014 annual emission rates from an emission rate equal to the average of its 2018 and 2019 annual emission rates. These emission rates are displayed in Table VI-9.

Table VI-9 Modeled Emissions for Class II Increment Analysis

Source ID	$PM_{2.5}$ Annual (tpy)
P_3	0.000
P_51_54	2.720
P_55	0.000
P_56	-0.010
P_61	-0.010
P_62	-0.050
P_63	0.100
P_64	0.400
P_65	0.150
P_67	0.410
P_68OLD	-1.270
P_68NEW	0.550
P_69	0.710
P_70	0.002
P_71	0.560
P_72	0.410
P_73	0.160
P_74	1.150
P_75	0.290
P_76	0.290
P_77	0.620
P_78	0.230
P_79	0.450
P_80	0.020

Source ID	$PM_{2.5}$ Annual (tpy)
P_81	0.000
P_82	0.000
P_83[(1)]	17.520
P_85[(1)]	17.520
P_86	51.296
P_87	6.880
P_88	4.770
P_89	0.390
P_90	0.410
P_91	0.610
P_92	0.000
P_141_1	0.220
P_141_2	0.120
P_143_1	-0.011
P_143_2	0.002
P_143_3	0.002
P_143_4	0.050
P_143_5	-0.011
P_143_6	-0.011
P_143_7	-0.011
P_143_8	-0.011
P_143_9	-0.011
P_143_10	-0.011
P_143_11	-0.002
P_143_12	-0.002
P_143_13	-0.002
P_143_14	-0.002
P_164	0.000
P_165	0.270
OFFSTE1	0.000
OFFSTE2	0.000
OFFSTE3	0.000
OFFSTE4	0.000
OFFSTE5	0.000
OFFSTE6	0.000
OFFSTE7	0.000
OFFSTE8	0.000
OFFSTE9	0.000

Source ID	$PM_{2.5}$ Annual (tpy)
OFFSTE10	0.000
OFFSTE11	0.000
OFFSTE12	0.000
OFFSTE13	0.000
OFFSTE14	0.000
OFFSTE15	0.000
OFFSTE16	0.000
OFFSTE17	0.000
OFFSTE18	0.000
OFFSTE22	0.000
OFFSTE23	0.561
OFFSTE24	-5.226
OFFSTE25	0.145
OFFSTE26	-2.933
WSC_PC	-0.240
WSC_BF	-0.007
WSC_KC	0.012
WSC_LF	0.018
WSC_B5	-0.004

(1)For $PM_{2.5}$ annual, "NORM" produced the highest impacts.

The results of the Class II Increment analysis are displayed in Table VI-10, demonstrating compliance with the annual averaging period increment.

Table VI-10 Class II Increment Analysis Results

Pollutant	Averaging Period	Model Conc. (μg/m³)	Secondary Impact Conc. (μg/m³)	Total Conc. (μg/m³)	Class II Increment (μg/m³)	% of Increment
$PM_{2.5}$	Annual	0.48(1)	0.00007	0.48	4	12%

(1)Receptor with the maximum annual concentration in the 5-year period.

PSD Class I Air Quality Analysis

A significant impact analysis was performed to evaluate whether the project's net emissions increases of PM_{10} and $PM_{2.5}$ would indicate a modeled impact in the area near the site that would exceed applicable PSD Class I SILs. Receptors were placed in a circle at 50 km from the project site, and the maximum modeled impact at this 50 km arc was compared to the applicable Class I SIL. All nearby Class I areas are located greater than 100 km from the site. Modeled emissions increases were the same as those shown in Table VI-4. The "NORM" scenario produced the highest PM_{10} and $PM_{2.5}$ annual results. The results of this analyses are presented in Table VI-11.

Table VI-11 Class I Significant Impact Analysis Results

Pollutant	Avg. Period	Model Conc. (µg/m³)	Secondary Impact Conc. (µg/m³)	Total Conc. (µg/m³)	SIL (µg/m³)
PM_{10}	Annual	0.0038[(1)]	-	0.0038	0.2
$PM_{2.5}$	Annual	0.0038[(1)]	0.00007	0.0039	0.03

[(1)]Receptor with the maximum annual concentration in the 5-year period.

PSD Class I Area Impact Analysis

In accordance with the provisions of ARM 17.8.825 and ARM 17.8.1106 (visibility only), Phillips 66 evaluated the potential for the "Billings Projects for 2022" to impact the air quality related values (AQRVs) of nearby Class I areas.

A "Q/d" screening analysis was performed by summing together the net emissions increases of NO_x, PM_{10}, SO_2, and H_2SO_4 (Q) and dividing that by the distance to the Class I area (d). The results are shown in Table VI-12. Because each Q/d result is considerably less than 10, the "Billings Projects for 2022" is not expected to negatively impact the AQRVs of the areas.

Table VI-12 Class I "Q/d" results

Class I Area	Q (tpy)	d (km)	"Q/d"
North Absaroka Wilderness Area	165.73	138	1.20
Yellowstone National Park	165.73	145	1.14
Northern Cheyenne Reservation	165.73	147	1.13
Washakie Wilderness Area	165.73	171	0.97
UL Bend Wilderness Area	165.73	193	0.86
Teton Wilderness Area	165.73	200	0.83
Grand Teton National Park	165.73	259	0.64
Fitzpatrick Wilderness Area	165.73	271	0.61
Gates of the Mountains Wilderness Area	165.73	276	0.60
Red Rock Lakes Wilderness Area	165.73	277	0.60

Bridger Wilderness Area	165.73	285	0.58

In addition, Phillips 66 performed the analysis presented in ARM 17.8.1110(5) and determined the federal Class I areas visibility monitoring requirements of ARM 17.8.1110 be waived for the "Billings Projects for 2022", because "V" is less than 0.5. The results of this analysis are in Table VI-13.

Table VI-13 Federal Class I Area ARM 17.8.1110(5) Results

Class I Area	NO_x Emissions (tpy)	d (km)	"V"
North Absaroka Wilderness Area	94.79	138	0.07
Yellowstone National Park	94.79	145	0.07
Washakie Wilderness Area	94.79	171	0.06
UL Bend Wilderness Area	94.79	193	0.05
Teton Wilderness Area	94.79	200	0.05
Grand Teton National Park	94.79	259	0.04
Fitzpatrick Wilderness Area	94.79	271	0.04
Gates of the Mountains Wilderness Area	94.79	276	0.04
Red Rock Lakes Wilderness Area	94.79	277	0.04
Bridger Wilderness Area	94.79	285	0.03

<u>Additional Impact Analysis</u>

No associated permanent industrial growth was noted to occur due to the "Billings Projects for 2022" project due to i) the site is an established facility that has consistently operated for decades and ii) the project did not increase the site's crude processing capacity. The project did not require any municipal infrastructure construction activities that would have impacted the Billings area air quality.

Level I and Level II Visibility Analyses were performed by Phillips 66 using VISCREEN, and the results show that the "Billings Projects for 2022" would not impair local visibility. Phillips 66 provided a soils and vegetation analysis that demonstrates that emissions increases are not expected to have a harmful impact on soils and vegetation in the area of the site.

DEQ determined that the project-related PM_{10} and $PM_{2.5}$ increases (with offsite facility and secondary $PM_{2.5}$ impacts) will not cause or contribute to an exceedance of a federal or state ambient air quality standard, will not exceed a PSD Class I or II increment, will protect Class I AQRVs including visibility, and will not impair the surrounding environment such as community/industrial growth, soils, crops, and vegetation. This decision was based on the air dispersion modeling with qualitative/quantitative analyses. The full modeling analysis submitted with the MAQP application is on file with DEQ.

VII. Taking and Damaging Implication Analysis

As required by 2-10-105, MCA, the DEQ conducted a private property taking and damaging assessment which is located in the attached environmental assessment and is located in the table below.

YES	NO	
X		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	X	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	X	3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)
	X	4. Does the action deprive the owner of all economically viable uses of the property?
	X	5. Does the action require a property owner to dedicate a portion of property or to grant an easement? [If no, go to (6)].
		5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests?
		5b. Is the government requirement roughly proportional to the impact of the proposed use of the property?
	X	6. Does the action have a severe impact on the value of the property? (consider economic impact, investment-backed expectations, character of government action)
	X	7. Does the action damage the property by causing some physical disturbance with respect to the property in excess of that sustained by the public generally?
	X	7a. Is the impact of government action direct, peculiar, and significant?
	X	7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded?
	X	7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question?
	X	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

VIII. Environmental Assessment

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

DRAFT ENVIRONMENTAL ASSESSMENT

July 2, 2025

Air Quality Permitting Services Section
Air Quality Bureau
Air, Energy and Mining Division
Montana Department of Environmental Quality

PROJECT/SITE NAME: Billings Refinery

APPLICANT/COMPANY NAME: Phillips 66 Company

Montana Air Quality Permit #2619-46

LOCATION: The facility location is 401 South 23rd Street, Billings, MT.

Section 2, Township 1S, Range 26E

COUNTY: Yellowstone

PROPERTY OWNERSHIP: FEDERAL STATE PRIVATE X

TABLE OF CONTENTS

TABLE OF CONTENTS

OVERVIEW OF PROPOSED ACTION

Authorizing Action

Pursuant to the Montana Environmental Policy Act (MEPA), Montana agencies are required to prepare an environmental review for state actions that may have an impact on the Montana environment. The Proposed Action is a state action that may have an impact on the Montana environment; therefore, the Montana Department of Environmental Quality (DEQ) must prepare an environmental review. This EA will examine the proposed action and alternatives to the proposed action and disclose potential and proximate impacts that may result from the proposed and alternative actions. DEQ will determine the need for additional environmental review based on consideration of the criteria set forth in Administrative Rules of Montana (ARM) 17.4.608.

Description of DEQ Regulatory Oversight

DEQ implements the Clean Air Act of Montana, §§ 75-2-101, et seq., (CAA) Montana Code Annotated (MCA), overseeing the development of sources of regulated pollutants and associated facilities. DEQ has authority to analyze proposed emitting units subject to rule established in ARM 17.8.743.

Proposed Action

Phillips 66 Company, Billings Refinery (Phillips) has applied for a Montana Air Quality Permit (MAQP) modification under the CAA. The MAQP regulates the Billings Refinery. This action would increase the throughput of as oil through the Fluidized Catalytic Cracking Unit (FCCU), from 24,000 barrels per day (bbl/day) to 26,000 bbl/day. Phillips 66 also requested that the No. 3 H_2 Plant Reformer and Heater as well as the No. 3 H_2 Plant PSA Off-gas Vent be removed from the MAQP. For the purpose of this EA, DEQ will only analyze the increase in throughput for the FCCU because the removal of the No. 3 H_2 Plant Reformer and Heater as well as the No. 3 H_2 Plant PSA Off-gas Vent are considered an administrative change to the MAQP. DEQ may not approve a proposed project contained in an application for an air quality permit unless the project complies with the requirements set forth in the CAA of Montana and the administrative rules adopted thereunder, ARMs 17.8.101 et. seq. The proposed action would be located on privately owned land, in Yellowstone County, Montana. All information included in this EA is derived from the permit application, discussions with the applicant, analysis of aerial photography, topographic maps, and other research tools.

Table 1. Summary of Proposed Action

General Overview	**The action is for an increase in barrels per day of gasoil through the FCCU.**
Duration & Hours of Operation	**Construction: Construction for the proposed action has already taken place and has been approved in previous permitting actions.** **Operation: Continuous operation depending upon talc processing throughput.**
Estimated Disturbance	**There will be no disturbances associated with the proposed action.**
Construction Equipment	**There will be no equipment used associated with the proposed action.**
Personnel Onsite	**Construction: None.** **Operation: No new permanent employees would be anticipated as the facility is normally unstaffed.**
Location and Analysis Area	**Location: The facility location is for 45.780089°N, latitude and –08.44361°W, longitude. Section 2, Township 1S, Range 26E** **Analysis Area: The area being analyzed as part of this environmental review includes the immediate project area (Figure 1), as well as neighboring lands surrounding the analysis area, as reasonably appropriate for the impacts being considered.**

Table 2. The applicant is required to comply with all applicable local, county, state, and federal requirements pertaining to the following resource areas.

Air Quality	**Yellowstone County is designated as unclassified/attainment area.**
Water Quality	**This permitting action would not affect water quality. Phillips is required to comply with the applicable local, county, state and federal requirements pertaining to water quality.**
Erosion Control and Sediment Transport	**This permitting action would not affect erosion control and sediment transport. Phillips 66 is required to comply with the applicable local, county, state and federal requirements pertaining to erosion control and sediment transport.**
Solid Waste	**This permitting action would not affect solid waste in the area. Phillips 66 is required to comply with the applicable local, county, state and federal requirements pertaining to solid waste.**
Cultural Resources	**This permitting action would not affect cultural resources. Phillips 66 is required to comply with the applicable local, county, state and federal requirements pertaining to cultural resources.**
Hazardous Substances	**This permitting action would not contribute to any hazardous substances. Phillips 66 is required to comply with the applicable local, county, state and federal requirements pertaining to hazardous substances.**

Reclamation	**This permitting action would not require any reclamation.**

Table 3. Cumulative Impacts

Past Actions	**There are no recent similar permitting actions at this site.**
Present Actions	**This permitting action increases the daily barrels per day of gas-oil through the FCCU.**
Related Future Actions	**DEQ is not currently aware of any future projects from Phillips 66 for this facility. Any future projects would be subject to a new permit application.**

Purpose, Need, and Benefits

DEQ's purpose in conducting this environmental review is to act upon Phillips 66's application for a MAQP to conduct facility improvements to throughput operaitons. DEQ's action on the permit application is governed by § 75-2-201, et seq., Montana Code Annotated (MCA) and the Administrative Rules of Montana (ARM) 17.8.740, et seq.

The applicant's purpose and need, as expressed to DEQ in seeking this action, is to increase the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU.

Figure 1. General Location of the Proposed Project

Other Governmental Agencies and Programs with Jurisdiction

The proposed action would be located on private land owned by the applicant. All applicable local, state, and federal rules must be adhered to, which may include other local, state, federal, or tribal agency jurisdiction. Other governmental agencies which may have overlapped, or additional jurisdiction include but may not be limited to: Montana Board of Oil and Gas, and Montana Public Service Commissions.

EVALUATION OF AFFECTED ENVIRONMENT AND IMPACT BY RESOURCE

The impact analysis will identify and evaluate the proximate direct and secondary impacts TO THE PHYSICAL ENVIRONMENT AND POPULATION IN THE AREA TO BE AFFECTED BY THE PROPOSED PROJECT. *Direct impacts* occur at the same time and place as the action that causes the impact. *Secondary impacts* are a further impact to Montana's environment that may be stimulated, induced by, or otherwise result from a direct impact of the action (ARM 17.4.603(18)). Where impacts would occur, the impacts will be described in this analysis. When the analysis discloses environmental impacts, these are proximate impacts pursuant to 75-1-201(1)(b)(iv)(A), MCA.

Cumulative impacts are the collective impacts on Montana's environment within the borders of Montana of the Proposed Action when considered in conjunction with other past and present actions related to the Proposed Action by location and generic type. Related future actions must also be considered when these actions are under concurrent consideration by any state agency through pre-impact statement studies, separate impact statement evaluation, or permit processing procedures (ARM 17.4.603(7)). The project identified in Table 1 was analyzed as part of the cumulative impacts assessment for each resource subject to review, pursuant to MEPA (75-1-101, et. *seq*).

The duration of the proposed action is quantified as follows:

- **Construction Impacts (short-term):** These are impacts to the environment that would occur during the construction period, including the specific range of time.

- **Operation Impacts (long-term)**: These are impacts to the environment during the operational period of the proposed action, including the anticipated range of operational time.

The intensity of the impacts is measured using the following:

- **No impact**: There would be no change from current conditions.

- **Negligible**: An adverse or beneficial effect would occur but would be at the lowest levels of detection.

- **Minor**: The effect would be noticeable but would be relatively small and would not affect the function or integrity of the resource.

- **Moderate**: The effect would be easily identifiable and would change the function or integrity of the resource.

- **Major**: The effect would alter the resource.

1. Geology and Soil Quality, Stability and Moisture

This section includes the following resource areas, as required in ARM 17.4.609: Geology; Soil Quality, Stability, and Moisture

Affected Environment

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

The affected area is primarily an industrial complex and consists of mainly asphalt cement, crude oil piping infrastructure, and crude oil refining infrastructure with associated equipment. The Yellowstone alluvial valley in the West Billings area is underlain by a relatively shallow, thin, unconfined to semi-confined aquifer system. Stratigraphic components of this system include the shale base underlying the aquifer, terrace alluvial gravel aquifers, and a fine-grained sediment cap. In the project area, the Yellowstone River has cut its valley 200–300 feet into late Cretaceous shale formations of the Colorado Group. The Colorado Group is exposed south of the valley and underlies the alluvial deposits of the valley (Lopez, 2000). The approximately 2,000-foot-thick shale sequence is typically a poor source of ground water, with low yields and poor water quality. The shale bedrock surface has been scoured by past erosion of the Yellowstone River. Deeper channel cuts and terrace cut benches are evident in the bedrock topography (plate 1). The shale at the base of the aquifer is typically weathered to a dense clay that is relatively impermeable and does not provide significant recharge to or discharge from the alluvial aquifer system. The valley is bounded on the north by a 300-foot-high cliff formed by the Eagle Sandstone and the Telegraph Creek Formation. These formations are Cretaceous, interbedded sandstone and shale that dip gently northward and are not present under the valley in the project area (Lopez, 2000).

Direct Impacts

There will be no direct construction or operational impacts to geology, soil quality, stability, or moisture as a result of the project. The current site is an already developed petroleum refinery with no new ground disturbances.

Secondary Impacts

There will be no secondary construction or operational impacts to geology or soil quality, stability, and moisture. The current site is an already developed petroleum refinery with no new ground disturbances.

Cumulative Impacts

There will be no cumulative impacts to geology or soil quality, stability, and moisture. The current site is an already developed petroleum refinery with no new ground disturbances.

2. Water Quality, Quantity, And Distribution

This section includes the following resource areas, as required in ARM 17.4.609: Water Quality, Quantity and Distribution

Affected Environment

This project would not impact any surface or groundwater in the area. The proposed project is *located within the existing property boundary of the refinery and will be confined to the Phillips 66 property boundary.*

Direct Impacts

No direct construction or operational impacts to water quality, quantity, and distribution would be expected as a result of the proposed action because water is not used in the FCCU process.

Secondary Impacts

No secondary construction or operational impacts to water quality, quantity, or distribution. The current site is an already developed petroleum refinery.

Cumulative Impacts

No cumulative impacts are expected because of the proposed project based on direct and secondary impacts.

3. Air Quality

This section includes the following resource areas, as required in ARM 17.4.609: Air Quality

Affected Environment

Air quality in the area affected by the proposed project is currently attainment for the applicable SO_2 NAAQS under a Maintenenece Plan established in June 2016. Otherwise, the affected area is unclassifiable or in compliance with all other applicable NAAQS. Existing sources of air pollution in the area include emissions from other industrial sources in the vicinity of the Phillips 66 refinery.

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

Applicants are required to comply with all laws relating to air, such as the Federal Clean Air Act, NAAQS set by the Environmental Protection Agency (EPA), and the Clean Air Act of Montana.

In addition, MAQP #2619-46 provides legally enforceable conditions regarding the emitting units themselves, pollution controls, and requires the applicant to take reasonable precautions to limit fugitive dust from this location.

Direct Impacts:

Emissions resulting from the permit action would be considered minor. Further, no air quality restrictions exist for the affected area; therefore, the proposed project would not be expected to cause or contribute to a violation of the applicable NAAQS for any regulated pollutant. Therefore, any direct impacts would be short-term, negligible, consistent with existing impacts, and mitigated by implementation of enforceable limits, conditions, and reasonable precautions.

Adverse air quality impacts would be minor because of the proposed project. See permit analysis for more information regarding air quality impacts. The majority of pollutants from the proposed project would be related to tanks used to store the gas oil and its derivatives after the catalytic cracking process. This would result in the release of NO_X, CO, SO_X, VOCs, *and particulate matter.*

The emission inventory, located in Section IV of the MAQP Analysis and represents new potential emissions associated with the proposed action of an increase of 24,000 bbl/day to 26,000 bbl/day and includes the removal of the No. 3 H2 Plant Reformer and Heater as well as the No. 3 H2 Plant PSA Off-gas Vent.

Overall refinery emissions.

Reevaluation of MAQP 2619-39 Project Emissions - Updated for 26,000 bpd Annual Average								
Source	Estimated Project Emissions (tpy)							
	CO	NOx	SO_2	PM (filt)	PM_{10}	$PM_{2.5}$	VOC	CO_{2e}
Project only or net emissions increase (whichever is higher) Sept_2020 App[1]	227.43	94.79	36.83	19.4	33.88	33.22	22.75	243,782
FCCU @ 24,000 bpd (baseline)	133.80	72.09	26.32	53.22	47.35	47.35	0.00	237,706
FCCU @ 26,000 bpd	144.96	78.10	28.52	57.65	51.29	51.29	0.00	257,515
Downstream impacts - Tanks							6.70	
No. 3 H_2 Plant Reformer Heater	-14.98	-17.48	-0.13	-0.59	-1.53	-1.05	-1.23	-111,795
No. 3 H_2 Plant PSA Off-Gas Vent	-26.82	0	0	0	0	0	0	-160
Change in emissions[2]	-30.64	-11.47	2.06	3.84	2.42	2.90	5.47	-92,146
PSD Applicability Emissions[3]	196.79	83.32	38.89	23.24	36.30	36.12	28.22	151,636
PSD Significance Threshold	100	40	40	25	15	10	40	75,000
Change?	Already PSD	Already PSD	N/A	N/A	Already PSD	Already PSD	N/A	Already PSD

Project specific emissions.

Pollutant	Project-Only Emissions Increase (tpy)	Project-Only Emissions Decrease (tpy)	PSD Significant Threshold (tpy)	PSD Significant? (Yes/No)
CO	11.16	-41.80	100	Yes, already PSD
NO_X	6.01	-17.48	40	Yes, already PSD
PM	4.43	-0.59	25	N/A
PM_{10}	3.94	-1.53	15	Yes, already PSD
$PM_{2.5}$	3.94	-1.05	10	Yes, already PSD
SO_2	2.81	-0.13	40	N/A
VOC	0.00	-1.23	40	N/A

Secondary Impacts:

Emissions from the proposed project would use already established BACT from previous, already approved permit actions and would not be expected to cause or contribute to a violation of the health and welfare-based primary and secondary NAAQS. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings.

See permit analysis for more detailed information regarding air quality impacts. Any adverse impacts would be long-term and minor. No beneficial secondary impacts would be expected because of the proposed project.

Cumulative Impacts:

Cumulative impacts from the increase in bbl/day are restricted by conditions and limits contained in the MAQP; therefore, any expected air quality impacts would be minor. The Yellowstone County area also has other, similar stationary sources, that all contribute to the overall air quality in Yellowstone County, Montana. The cumulative impacts of these other emitters and the proposed action would not have an adverse impact to air quality. Impacts from the Permitting Action are limited by enforceable conditions and limits contained in the MAQP and BACT must be used.

Because emissions from the proposed project, and all other similar or related projects located in the affected area are regulated, any adverse cumulative impacts to air quality would be long-term and minor.

4. Vegetation Cover, Quantity, and Quality

This section includes the following resource areas, as required in ARM 17.4.609: Vegetation Cover, Quantity and Quality

Affected Environment

The affected area is primarily of industrial land within the city of Billings, MT.

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

Direct Impacts:

No direct construction or operational impacts to vegetative cover, quantity, or quality would be expected as a result of the proposed action because there are no new areas of disturbance associated with the proposed action.

Secondary Impacts:

No secondary construction or operational impacts to vegetative cover, quantity, or quality would be expected as a result of the proposed action because there are no new areas of disturbance associated with the proposed action.

Cumulative Impacts:

There will be no cumulative impacts to vegetative cover, quantity, or quality associated with the proposed action based on direct and secondary impacts.

5. Terrestrial, Avian, and Aquatic Life and Habitats

This section includes the following resource areas, as required in ARM 17.4.609: Terrestrial and Aquatic Life and Habitats; Unique, Endangered, Fragile, or Limited Environmental Resources

Affected Environment

The affected area is primarily industrial land within the city of Billings, MT.

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

Direct Impacts:

No direct construction or operational impacts to vegetative cover, quantity, or quality would be expected as a result of the proposed action because there are no new areas of disturbance associated with the proposed action.

Secondary Impacts:

No secondary construction or operational impacts to vegetative cover, quantity, or quality would be expected as a result of the proposed action because there are no new areas of disturbance associated with the proposed action.

Cumulative Impacts:

There will be no cumulative impacts to vegetative cover, quantity, or quality associated with the proposed action based on direct and secondary impacts.

6. Unique, Endangered, Fragile, or Limited Environmental Resources

This section includes the following resource areas, as required in ARM 17.4.609: Unique, Endangered, Fragile, or Limited Environmental Resources.

Affected Environment

DEQ did not conduct a search using the Montana Natural Heritage Program (MTNHP) because the proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

The proposed project is not in core, general or connectivity sage grouse habitat, as designated by the Sage Grouse Habitat Conservation Program at: http://sagegrouse.mt.gov.

Direct Impacts:

No direct construction or operational impacts to unique, endangered, fragile, or limited environmental resources would be expected as a result of the proposed action. The affected area is an already developed petroleum refinery with no terrestrial, avian, or aquatic life or habitats located within the property boundary or more specifically, the FCCU where the project is proposed to occur. There may be resident bird species (pigeons and other small avian species) located on the property, but it is unlikely that the proposed project would affect them due to the continuous operation of the refinery.

Secondary Impacts:

No secondary impacts from construction or operations are expected as a result of the proposed project. The affected area is an already developed petroleum refinery with no terrestrial, avian, or aquatic habitats located within the property boundary or more specifically, the FCCU where the project is proposed to occur.

Because the area surrounding the FCCU is an already developed industrial complex, no species are expected to be present.

Cumulative Impacts:

There will be no cumulative impacts to unique, endangered, fragile, or limited environmental resources associated with the proposed action based on direct and secondary impacts.

7. Historical and Archaeological Sites

This section includes the following resource areas, as required in ARM 17.4.609: Historical and Archaeological Sites

Affected Environment

The Montana State Historic Preservation Office (SHPO) was not notified of the application because the proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

It is SHPO's position that any structure over fifty years of age are considered historic and are potentially eligible for listing on the National Register of Historic Places. If any structures are within the Area of Potential Effect, and are over fifty years old, SHPO recommends that they be recorded, and a determination of their eligibility be made prior to any disturbance taking place.

Direct Impacts:

No direct construction or operational impacts to historical or archaeological sites would be expected as a result of the proposed action because there are no new structures or modifications to any existing structures as part of the proposed action.

Secondary Impacts:

No secondary construction or operational impacts to historical or archaeological sites would be expected as a result of the proposed action because there were no new structures or modifications to any existing structures.

Cumulative Impacts:

There will be no cumulative impacts to historical or archaeological sites associated with the proposed action based on direct and secondary impacts.

8. Aesthetics

This section includes the following resource areas, as required in ARM 17.4.609: Aesthetics

Affected Environment

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

Direct Impacts:

No direct construction or operational impacts to the aesthetics would be expected as a result of the proposed action because there are no new structures or modifications to any existing structures affecting the exiting aesthetics for the facility associated with the proposed project.

Secondary Impacts:

No secondary construction or operational impacts to the aesthetics are expected as a result of the proposed action because there are no new structures or modifications to any existing structures effecting the exiting aesthetics for the facility associated with the proposed project.

Cumulative Impacts:

There will be no cumulative impacts to the aesthetics associated with the proposed action based on direct and secondary impacts.

9. Demands on Environmental Resources of Land, Water, Air, or Energy

This section includes the following resource areas, as required in ARM 17.4.609: Demands on Environmental Resources of Land, Water, Air, or Energy

Affected Environment

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

Direct Impacts:

No direct construction or operational impacts on demands of environmental resources of land, water, or air are expected. However, the proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU which would increase the facilities demands for energy which would be considered minor and long-term.

Secondary Impacts:

No secondary construction or operational impacts demands of environmental resources of land, water, air, or energy are expected as a result of the proposed action.

Cumulative Impacts:

There would be no cumulative impacts to the demands of environmental resources of land, water, or air. Minor and long-term impacts would be associated with the proposed action due to the increase of energy to accommodate an additional 2,000bbl/day of gas oil through the FCCU.

10.Impacts on Other Environmental Resources

This section includes the following resource areas, as required in ARM 17.4.609: Impacts on Other Environmental Resources

Affected Environment

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

Direct Impacts:

No direct construction or operational impacts on demands of environmental resources would be expected as a result of the proposed action because the proposed action is located inside of an existing facility and would not affect any outside environmental resources.

Secondary Impacts:

No secondary construction or operational impacts demands of environmental resources would be expected as a result of the proposed action because the proposed action is located inside of an existing facility and would not affect any outside environmental resources.

Cumulative Impacts:

No other impacts to environmental resources, beyond the resource areas already covered within this EA would result in any known additional cumulative impacts based on direct and secondary impacts.

11.Human Health and Safety

This section includes the following resource areas, as required in ARM 17.4.609: Impacts on Human Health and Safety

Affected Environment

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

Direct Impacts:

No direct construction or operational impacts to human health and safety would be expected as a result of the proposed action. Emissions released into the human environment from the facility due to the proposed action would be considered minor.

Secondary Impacts:

No secondary construction or operational impacts to human health and safety are expected as a result of the proposed action.

Cumulative Impacts:

No other affects to human health and safety, beyond the resource areas already covered within this EA would result in any known additional cumulative impacts.

12.Industrial, Commercial, and Agricultural Activities and Production

This section includes the following resource areas, as required in ARM 17.4.609: Impacts on Human Health and Safety

Affected Environment

The effected area consists primarily of industrial land. The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

Direct Impacts:

No direct construction or operational impacts to commercial or agricultural activities are expected. Minor, long-term impacts to industrial production would be expected as a result of the proposed action due to the increase in bbl/day of gas oil processed through the FCCU.

Secondary Impacts:

No secondary construction impacts to industrial, commercial, or agricultural activities are expected with the proposed project. However, minor operational impacts to and production would be expected as a result of the proposed action because the proposed action increases the facilities production capacity by 2000 bbl/day.

Cumulative Impacts:

No other environmental resources, beyond the resource areas already covered within this EA would result in any known additional cumulative impacts based on direct and secondary impacts.

13.Quantity and Distribution of Employment

This section includes the following resource areas, as required in ARM 17.4.609: Impacts on Quantity and Distribution of Employment

Affected Environment

There are already existing staff and resources employed by Phillips 66 in the area, and these resources would be used to operate this facility. The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

Direct Impacts:

Phillips 66 would use existing staff to operate the FCCU. Therefore, any direct impacts to the quantity and distribution of employment in the affected area would be short-term and negligible. No adverse direct impacts would be expected because of the proposed project.

Secondary Impacts:

Phillips 66 would use existing staff to operate the proposed facility. Therefore, any secondary impacts to the quantity and distribution of employment in the affected area would be long-term and negligible. No adverse secondary impacts would be expected because of the proposed project.

Cumulative Impacts:

Short-term and negligible impact would be expected on long-term employment from the proposed action because the facility would not be expected to create any permanent new jobs.

14.Local and State Tax Base and Tax Revenue

This section includes the following resource areas, as required in ARM 17.4.609: Impacts on Local and State Tax Base and Tax Revenue

Affected Environment

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

Direct Impacts:

No direct construction or operational impacts to local and state tax base and tax revenue would be expected as a result of the proposed action. However, because the proposed project would be small by industrial standards any direct impacts to the local and state tax base and tax revenues would be long-term, negligible to minor, and beneficial. No adverse direct impacts would be expected because of the proposed project.

Secondary Impacts:

Local, state and federal governments would be responsible for appraising the property, setting tax rates, collecting taxes, from the companies, employees, or landowners benefitting from the proposed operation. Further, Phillips 66 would be responsible for accommodation of any increased taxes associated with operation of the proposed facility. Therefore, any secondary impacts would be negligible to minor, consistent with existing impacts in the affected area, and beneficial. No adverse secondary impacts would be expected because of the proposed project.

Cumulative Impacts:

Long-term beneficial negligible to minor impacts to local and state tax base and tax revenues are anticipated from this permitting action.

15.Demand for Government Services

This section includes the following resource areas, as required in ARM 17.4.609: Impacts on Demands for Government Services

Affected Environment

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

Direct Impacts:

The air quality permit has been prepared by state government employees as part of their day-to-day, regular responsibilities. Therefore, any adverse direct impacts to demands for government services is consistent with existing impacts and negligible. No beneficial direct impacts would be expected because of the proposed project.

Secondary Impacts:

Ongoing compliance inspections of facility operations would be accomplished by state government employees as part of their typical, regular duties and required to ensure the facility is operating within the limits and conditions listed in the air quality permit. Therefore, any adverse secondary impacts to demands for government services would be consistent with existing impacts and negligible. No beneficial secondary impacts would be expected because of the proposed project.

Cumulative Impacts:

Minor cumulative impacts are anticipated on government services with the proposed action and a minimal increase in impact would occur but regulators would likely combine visits to cover regulatory oversight needs.

16.Locally Adopted Environmental Plans and Goals

This section includes the following resource areas, as required in ARM 17.4.609: Impacts on Locally Adopted Environmental Plans and Goals

Affected Environment

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

DEQ has reviewed the Yellowstone County website and found no locally adopted environmental plans and goals for the area. Phillips 66 has indicated, in application number 2619-45_2025_05_21_APP that no known state, county, city, USFS, BLM, or tribal zoning or management plans and goals are known to potentially affect the site.

Direct Impacts:

No locally adopted environmental plans and goals were identified. Therefore, no direct impacts would be expected because of the proposed project.

Secondary Impacts:

No locally adopted environmental plans and goals were identified.; therefore, no secondary impacts to locally adopted environmental plans and goals would be expected because of the proposed project.

Cumulative Impacts:

No cumulative impacts to the locally adopted environmental plans and goals are anticipated since no direct impacts or secondary impacts were identified.

17.Access to and Quality of Recreational and Wilderness Activities

This section includes the following resource areas, as required in ARM 17.4.609: Impacts on Access to and Quality of Recreation and Wilderness Activities

Affected Environment

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

Direct Impacts:

There are no wilderness areas that occur in the vicinity of the proposed project. There are no public access to wilderness areas located within the Phillips 66 property footprint, therefore, no direct impacts to access and quality of recreational and wilderness activities would be expected as a result of the proposed project.

Secondary Impacts:

The effected area consists primarily of industrial lands. The project would have no impacts on the immediate area, therefore, no secondary impacts to access and quality of recreational and wilderness activities would be expected because of proposed facility operations.

Cumulative Impacts:

No cumulative impacts to access and quality of recreational and wilderness activities are anticipated as a result of the proposed permitting action based on direct and secondary impacts.

18.Density and Distribution of Population and Housing

This section includes the following resource areas, as required in ARM 17.4.609: Impacts on Density and Distribution of Population and Housing

Affected Environment

The affected area consists primarily of industrial lands. The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

Direct Impacts:

Phillips 66 would employ existing staff to operate the FCCU and would not be expected to increase or decrease in the local population outside of normal employee turnover. Therefore, no direct impacts to density and distribution of population and housing would be expected because of the proposed project.

Secondary Impacts:

Phillips 66 would employ existing staff to operate the facility and the proposed project would not be expected to otherwise result in an increase or decrease in the local population. Therefore, no secondary impacts to density and distribution of population and housing would be expected because of the proposed project.

Cumulative Impacts:

No cumulative impacts to density and distribution of population and housing are anticipated as a result of the proposed permitting. There are no impacts on the density and distribution of population and housing.

19.Social Structures and Mores

This section includes the following resource areas, as required in ARM 17.4.609: Impacts on Social Structures and Mores

Affected Environment

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

DEQ is not aware of any Native American cultural concerns that would be affected by the proposed action. Based on the information provided by the Applicant, it is not anticipated that this project would disrupt traditional lifestyles or communities.

The existing nature of the area affected by the proposed project is industrial.

Direct Impacts:

Construction and operation of the facility would not be expected to affect the existing customs and values of the affected population. Therefore, no direct impacts to the existing social structures and mores of the affected population would be expected because of the proposed project.

Secondary Impacts:

The existing nature of the area affected by the proposed project is industrial (petroleum refining) therefore, operation of the facility would not be expected to affect the existing customs and values of the affected population. Therefore, no secondary impacts to the existing social structures and mores of the affected population would be expected because of the proposed project.

Cumulative Impacts:

The increase in bbl/day would have negligible to minor cumulative impacts on the existing social structures because this site would be just one of many sites already operating in the area.

20.Cultural Uniqueness and Diversity

This section includes the following resource areas, as required in ARM 17.4.609: Impacts to Cultural Uniqueness and Diversity

Affected Environment

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

The existing nature of the area affected by the proposed project is industrial (petroleum refining). It is not anticipated that this project would cause a shift in some unique quality of the area.

Direct Impacts:

Phillips 66 would employ existing staff to operate the FCCU and would not be expected to result in an increase or decrease in the local population. Therefore, no direct impacts to the existing cultural uniqueness and diversity of the affected population would be expected because of the proposed action.

Secondary Impacts:

The existing nature of the area affected by the proposed project is industrial (petroleum refining). Further, Phillips 66 would employ existing staff to operate the facility and thus the proposed project would not be expected to result in an increase or decrease in the local population.

Therefore, no secondary impacts to the existing cultural uniqueness and diversity of the affected population are anticipated as a result of the proposed action.

Cumulative Impacts:

No cumulative impacts to cultural uniqueness and diversity are anticipated because the skills required by this project would be similar to other existing sites in the area and this project would be considered small by industrial standards.

*21.*Private Property Impacts

The proposed project would take place on private land owned by the applicant. DEQ's approval of MAQP 2619-46 would affect the applicant's real property. DEQ has determined, however, that the permit conditions are reasonably necessary to ensure compliance with applicable requirements under the CAA Act. Therefore, DEQ's approval of MAQP 2619-46 would not have private property-taking or damaging implications.

22.Other Appropriate Social and Economic Circumstances

This section includes the following resource areas, as required in ARM 17.4.609: Impacts to Other Appropriate Social and Economic Circumstances

Affected Environment

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. Physical changes to the refinery to accommodate the increase in bbl/day were approved in previous MAQP applications as part of a larger PSD modification to the refinery.

Direct Impacts:

DEQ is unaware of any other appropriate short-term social and economic circumstances in the affected area that may be directly impacted by the proposed project. Due to the nature of the proposed action, no further direct impacts would be expected because of the proposed project.

Secondary Impacts:

DEQ is unaware of any other appropriate long-term social and economic circumstances in the affected area that may be impacted by the proposed project. No further secondary impacts would be expected because of the proposed project.

Cumulative Impacts:

No cumulative impacts to any other appropriate social and economic circumstances are anticipated because no direct and secondary impacts were identified.

23.Greenhouse Gas Assessment

Affected Environment

The analysis area for this resource is limited to the activities regulated by the issuance of MAQP #2619-46 which provides an increase in bbl/day of fuel oil. The GHG emissions were calculated from the project operation of 26,000 bbl/day of fuel oil throughput into the FCCU.

For the purpose of this analysis, DEQ has defined greenhouse gas emissions as the following gas species: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and many species of fluorinated compounds. The range of fluorinated compounds includes numerous chemicals which are used in many household and industrial products.

Other pollutants can have some properties that also are similar to those mentioned above, but the EPA has clearly identified the species above as the primary Greenhouse Gases (GHGs). Water vapor is also technically a greenhouse gas, but its properties are controlled by the temperature and pressure within the atmosphere, and it is not considered an anthropogenic species.

Montana recently used the EPA State Inventory Tool (SIT) to develop a greenhouse gas inventory. This tool was developed by EPA to help states develop their own greenhouse gas inventories, and this relies upon data already collected by the federal government through various agencies. The inventory specifically deals with CO_2, CH_4, and N_2O and reports the total as CO_2e.

The SIT consists of eleven Excel based modules with pre-populated data that can be used as default settings or in some cases, allows states to input their own data when the state believes their own data provides a higher level of quality and accuracy.

Once each of the eleven modules is filled out, the data from each module is exported into a final "synthesis" module which summarizes all of the data into a single file. Within the synthesis file, several worksheets display the output data in a number of formats such as emissions by sector and emissions by type of greenhouse gas. The SIT data is currently updated through the year 2021, as it takes several years to validate and make new data available within revised modules.

The combustion of natural gas at the site would release GHGs primarily being CO2, N2O, and much smaller concentrations of incomplete combustion of fuel components including CH4 and other volatile organic compounds (VOCs).

Mobile emissions associated with this action are limited to construction of the site. This amount is insignificant and not included in the assessment. Additionally, there are no compressed gases, fire suppressants or refrigerants/air conditioning associated with this project which would have been considered Scope 1 emissions.

Direct Impacts

Operation of the FCCU with an increase of 2,000 bbl/day of gas oil for the proposed project would produce emissions containing GHGs.

The FCCU regenerator is a full burn regenerator and is used to burn off carbon deposits. Phillips 66 supplied DEQ with CO2e calculations based on actual carbon content from the regeneration process using the reporting rule contained in 40 Code of Federal Regulation (CFR) 98, Subpart Y, more specifically, 40 CFR 98.253.

Based on calculations for CO2e, emissions of GHGs from the FCCU would add an additional 19,812 tons of CO2e (t/CO2e) and increase the overall emissions from the FCCU and distillate storage tanks from 237,706 t/yr CO2e to 257,515 t/yr CO2e.

Secondary Impacts

GHG emissions contribute to changes in atmospheric radiative forcing, resulting in climate change impacts. GHGs act to contain solar energy loss by trapping longer wave radiation emitted from the Earth's surface and act as a positive radiative forcing component (BLM 2021). If a reader would like further details please see the BLM 2022 report at: Annual GHG Report.

The impacts of climate change throughout the Northern Great Plains of Montana include changes in flooding and drought, rising temperatures, and the spread of invasive species (BLM 2021).

Cumulative Impacts

DEQ has determined that the use of the default data provides a reasonable representation of *the GHG inventory for all of the state sectors, and an estimated annual GHG inventory by year.*

The proposed action may contribute 0.019812 million metric tons per year of CO2e. The estimated emission of 0.019812 million metric tones of CO2e for this proposed action would contribute 0.0004146% of Montanas annual CO_2e emissions.

Description of Alternatives

No Action Alternative: In addition to the proposed action, DEQ must also considered a "no action" alternative. The "no action" alternative would deny the approval of the proposed action. The applicant would lack the authority to conduct the proposed activity. Any potential impacts that would result from the proposed action would not occur. The no action alternative forms the baseline from which the impacts of the proposed action can be measured.

If the applicant demonstrates compliance with all applicable rules and regulations required for approval, the “no action” alternative would not be appropriate.

Other Reasonable Alternative(s): Describe any other alternatives that were considered.

Consultation

DEQ engaged in internal and external efforts to identify substantive issues and/or concerns related to the proposed project. Internal scoping consisted of internal review of the environmental assessment document by DEQ staff. External scoping efforts also included queries to the following websites/databases/personnel: https://www.yellowstonecountymt.gov/

A review of the Yellowstone County website, and listed department information did not indicate any specific planning documents that would be relative to this permitting action.

Public Involvement

The public comment period for this permit action is from 07/02/2025 through 07/17/2025. Public comments may be submitted to DEQ through the DEQ website, email, written letter, or in person.

Significance of Potential Impacts and Need for Further Analysis

When determining whether the preparation of an environmental impact statement is needed, DEQ is required to consider the seven significance criteria set forth in ARM 17.4.608, which are as follows:

- The severity, duration, geographic extent, and frequency of the occurrence of the impact;
- The probability that the impact will occur if the proposed action occurs; or conversely, reasonable assurance in keeping with the potential severity of an impact that the impact will not occur;
- Growth-inducing or growth-inhibiting aspects of the impact, including the relationship or contribution of the impact to cumulative impacts – identify the parameters of the proposed action;
- The quantity and quality of each environmental resource or value that would be affected, including the uniqueness and fragility of those resources and values;
- The importance to the state and to society of each environmental resource or value that would be affected;
- Any precedent that would be set as a result of an impact of the proposed action that would

commit the department to future actions with significant impacts or a decision in principle about such future actions; and
- Potential conflict with local, state, or federal laws, requirements, or formal plans.

Conclusions and Findings

DEQ finds that this action results in negligible impacts to air quality and GHG emissions in Yellowstone County, Montana.

No significant adverse impacts would be expected because of the proposed project. As noted through the draft EA, the severity, duration, geographic extent and frequency of the occurrence of the impacts associated with the proposed air quality project would be limited. The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU.

The proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU. The site is permitted to operate the FCCU 8,760 hours per calendar year using BACT for the control of emissions from the proposed operations.

As discussed in this EA, DEQ has not identified any significant impacts associated with the proposed actions for any environmental resource. DEQ does not believe that the activities proposed by the Applicant would have any growth-inducing or growth-inhibiting aspects, or contribution to cumulative impacts.

There are no unique or known endangered fragile resources in the project area and no underground disturbance would be required for this project.

There would be no impacts to view-shed aesthetics the proposed action increases the throughput of oil gas from 24,000 bbl/day to 26,000 bbl/day, through the FCCU.

Demands on the environmental resources of land, water, air, or energy would not be significant.

Impacts to human health and safety would not be significant as access roads would be closed to the public and because the site is on private land.

As discussed in this EA, DEQ has not identified any significant impacts associated with the proposed activities on any environmental resource.

Issuance of a Montana Air Quality Permit #2619-46 to the Applicant does not set any precedent that commits DEQ to future actions with significant impacts or a decision in principle about such future actions. If the Applicant submits another modification or proposes to amend the permit, DEQ is not committed to issuing those revisions.

DEQ would conduct an environmental review for any subsequent permit modifications sought by the Applicant pursuant to MEPA. DEQ would make permitting decisions based on the criteria set forth in the Clean Air Act of Montana.

Issuance of the Permit to the Applicant does not set a precedent for DEQ's review of other applications for Permits, including the level of environmental review. The level of environmental review decision is made based on case-specific consideration of the criteria set forth in ARM 17.4.608.

Finally, DEQ does not believe that the proposed air quality permitting action by the Applicant would have any growth-inducing or growth inhibiting impacts that would conflict with any local, state, or federal laws, requirements, or formal plans.

Based on a consideration of the criteria set forth in ARM 17.4.608, no significant adverse impacts to the affected human environment would be expected because of the proposed project. Therefore, preparation of an Environmental Impact Statement or EIS is not required, and the draft EA is deemed the appropriate level of environmental review pursuant to MEPA.

PREPARATION

Environmental Assessment and Significance Determination Prepared By:

John P. Proulx
Air Quality Engineering Scientist
Air Quality Permitting Services Section

Environmental Assessment Reviewed By:

Eric Merchant, Supervisor
Air Quality Permitting Services Section

Approved By:

______________________________	*July 2, 2025*
Eric Merchant, Supervisor Air Quality Permitting Services Section Air Quality Bureau Air, Energy, and Mining Division Department of Environmental Quality	Date

REFERENCES

- 2619-46_2025_05_21_APP – Application received from Tetra Tech on behalf of Phillips 66 Company on May 21, 2025. Additional information was received on May 28, 2025.

- Olson, J.L., and Reiten, J.C., 2002, Hydrogeology of the west Billings area: Impacts of land-use changes on water resources: Montana Bureau of Mines and Geology Report of Investigation 10, 32 p., 2 sheets.

- 2021 BLM Specialist Report on Annual Greenhouse Gas Emissions and Climate Trends, https://www.blm.gov/

- https://www.blm.gov/content/ghg/?year=2022

- https://www.yellowstonecountymt.gov/