DEQ
Montana Department of Environmental Quality

Air, Energy & Mining Division

July 7, 2022

Ron Colwell
Montana Renewables LLC
MRL Great Falls Renewable Fuels Plant
1900 Street NE
Great Falls, Montana 59404

Sent via email to: Ron.Colwell@calumetspecialty.com

RE: Final Permit Issuance for MAQP #5263-01

Dear Mr. Colwell:

Montana Air Quality Permit (MAQP) #5263-01 is deemed final as of July 7, 2022, by DEQ. As this is considered an Energy Development Project, the appeal period ends on July 21, 2022. This permit is for Montana Renewables LLC for a renewable fuels plant. All conditions of the Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

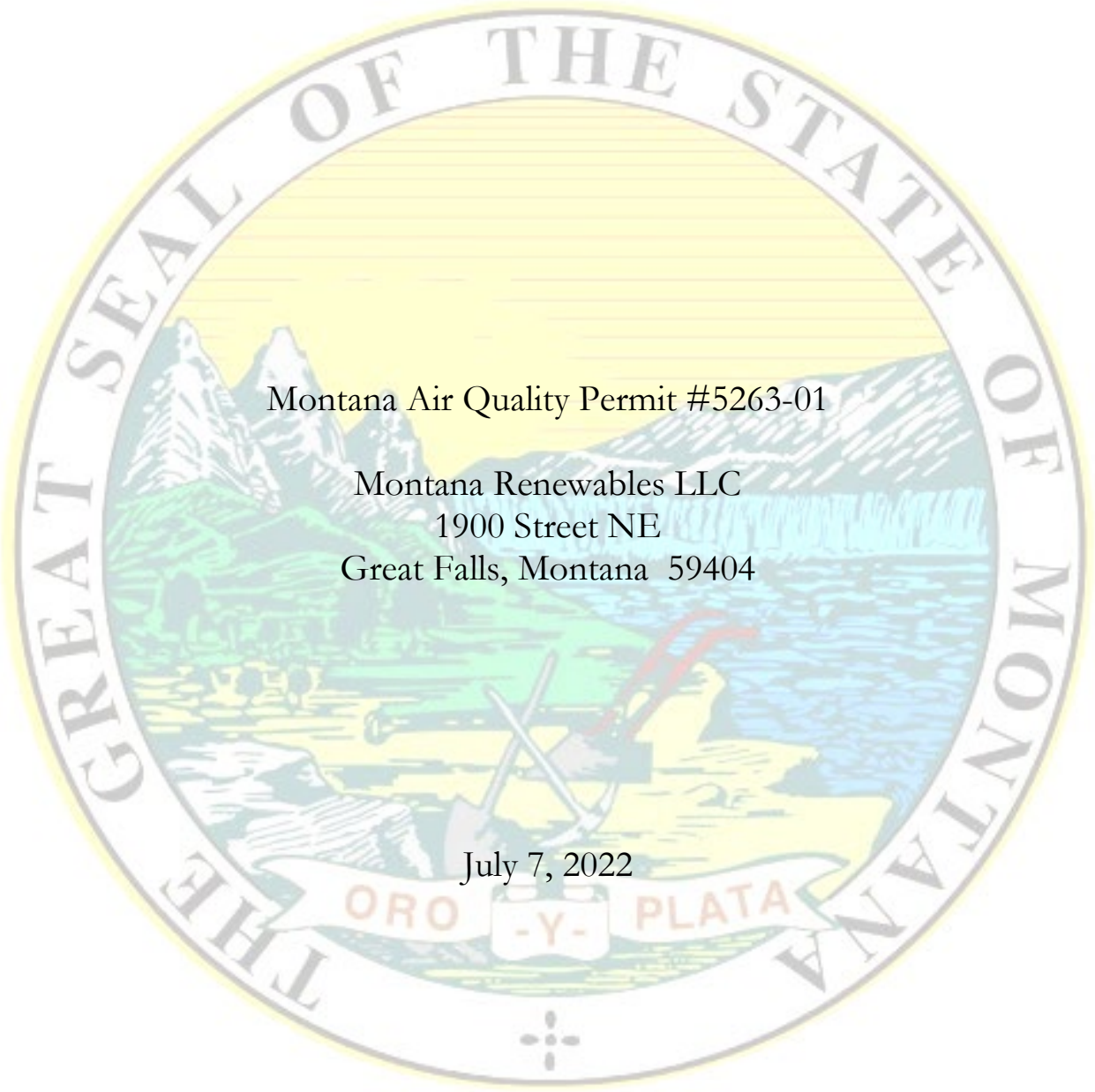
For DEQ,

Julie A. Merkel
Permitting Services Section Supervisor
Air Quality Bureau
(406) 444-3626

Craig Henrikson, P.E.
Environmental Engineer
Air Quality Bureau
(406) 444-6711

Enclosures

Montana Department of Environmental Quality
Air, Energy & Mining Division
Air Quality Bureau



Montana Air Quality Permit #5263-01

Montana Renewables LLC
1900 Street NE
Great Falls, Montana 59404

July 7, 2022

MONTANA AIR QUALITY PERMIT

Issued to: Montana Renewables LLC
1900 Street NE
Great Falls, Montana 59404

MAQP: #5263-01
Application Received: April 26, 2022
Application Complete: May 19, 2022
Preliminary Determination: May 26, 2022
Department's Decision: June 21, 2022
Permit Final: July 7, 2022

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

Section I: Permitted Facilities

A. Plant Location

The legal description of the site is the Northeast (NE) quarter of Section 1, Township 20 North, Range 3 East in Cascade County, Montana. The new renewable fuels plant would sit on the site currently occupied by the Montana Calumet Refinery. A map of the site is included in the Environmental Assessment attached to this permit.

B. Current Permit Action

On April 26, 2022, the Department of Environmental Quality (DEQ) received an application to modify MAQP #5263-00. Since the initial MAQP was issued on October 26, 2021, construction has begun for the new facility but the original design details have evolved to accommodate the latest project plan. The application has been submitted under the name Renewable Feed Flexibility Project. The primary change in the plant design entails installing a pretreatment unit (PTU) to allow the facility to treat raw renewable materials such as fats and oils which will result in the need to handle and transfer additional wastewater from the facility. This additional wastewater generation will require an additional storage tank as well as load-out facilities that use trucks, existing rail load-out infrastructure, or the installation of new rail load-out facilities. Finally, renewable kerosene and sustainable aviation fuel are also being added as renewable products produced at the facility. These two new planned products will require new tanks as well as changes in the planned use of other tanks. MRL also proposed to permit the MHC Fractionator Feed Heater (H-4102) which had earlier been planned for shutdown, and will now be called the RDU Fractionator Feed Heater (H-4102). Additional process equipment is also being permitted and is described in the MAQP analysis.

Section II: Conditions and Limitations

A. Emission Limitations

1. RDU Combined Feed Heater (H-4101)

a. NOx emissions shall not exceed 0.035 lb/MMBtu (Higher Heating Value) (HHV) on a 30-day rolling average basis using ultra-low NOx burners (ULNBs) and monitored via CEMS including an O_2 analyzer and NOx analyzer (ARM 17.8.752 and ARM 17.8.749).

b. MRL shall use good combustion practices and an oxygen monitoring system to control CO emissions which may not exceed 0.055 lb/MMBtu (HHV) on a 1-hour average (ARM 17.8.752 and ARM 17.8.749).

c. MRL shall utilize an oxygen monitoring system and good combustion practices to minimize PM (ARM 17.8.752 and ARM 17.8.749).

d. PM (filterable) emissions shall not exceed 0.00051 lb/MMBtu (HHV) on a 1-hour average (ARM 17.8.752 and ARM 17.8.749).

e. PM_{10} (filterable plus condensable) emissions shall not exceed 0.00051 lb/MMBtu (HHV) on a 1-hour average (ARM 17.8.752 and ARM 17.8.749).

f. $PM_{2.5}$ (filterable plus condensable) emissions shall not exceed 0.00042 lb/MMBtu (HHV) on a 1-hour average (ARM 17.8.752 and ARM 17.8.749).

g. MRL shall utilize an oxygen monitoring system and good combustion practices to minimize volatile organic compounds (VOCs) (ARM 17.8.752 and ARM 17.8.749).

h. The annual average firing rate of H-4101 shall not exceed 25 MMBtu/hr (HHV) (ARM 17.8.752 and ARM 17.8.749).

i. MRL shall conduct the work practice standards for minimizing CO required under 40 CFR 63 Subpart DDDDD (40 CFR 63 Subpart DDDDD, ARM 17.8.749 and ARM 17.8.342).

j. H-4101 shall only combust natural gas and RDU off-gas (ARM 17.8.749).

k. H-4101 shall not combust RDU off-gas fuel containing H_2S in excess of 30 ppmv. Additionally, the heater shall not combust RD off-gas fuel containing H_2S in excess of 10 ppmv on an annual average basis (ARM 17.8.749.)

l. Opacity shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304)

2. Hydrogen Plant #3 - Reformer Heaters (H-3815A and H-3815B)

   a. The annual average firing rate of each heater (H-3815A and H-3815B) shall not exceed 67.0 MMBtu/hr (HHV) (ARM 17.8.749).

   b. NOx emissions from each heater shall be controlled by an ULNB and the combined NOx emissions from the two heaters shall not exceed 0.051 lb/MMBtu (HHV) on a 30-day rolling average basis and monitored via CEMS including an O_2 analyzer and NOx analyzer (ARM 17.8.752 and ARM 17.8.749).

   c. MRL shall control PM (filterable), PM_{10} (filterable plus condensable) and $PM_{2.5}$ (filterable plus condensable) emissions from each heater by utilizing good combustion practices and only combusting low sulfur fuels (ARM 17.8.752 and ARM 17.8.749):

      i. PM (filterable) emissions shall not exceed 0.00051 lb/MMBtu (HHV) on a 1-hour average.

      ii. PM_{10} (filterable plus condensable) emissions shall not exceed 0.00051 lb/MMBtu (HHV) on a 1-hour average.

      iii. $PM_{2.5}$ (filterable plus condensable) emissions shall not exceed 0.00042 lb/MMBtu (HHV) on a 1-hour average.

   d. MRL shall control CO emissions using good combustion practices and CO emissions shall not exceed 0.03 lb/MMBtu (HHV) on a 1-hour average (ARM 17.8.752 and ARM 17.8.749).

   e. Opacity shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

   f. H-3815A and H-3815B shall only combust natural gas and PSA off-gas, which are inherently low sulfur fuels (ARM 17.8.749).

3. Hydrogen Plant #4 (H-4801). MRL shall comply with the following requirements:

   a. NOx emissions shall be controlled by an ULNB and shall not exceed 0.04 lb/MMBtu (HHV) on a 30-day rolling average basis and monitored via CEMS including an O_2 analyzer and NOx analyzer (ARM 17.8.752 and ARM 17.8.749).

   b. MRL shall use good combustion practices and a continuous oxygen monitoring system to control CO emissions which may not exceed 0.03 lb/MMBtu (HHV) on a 1-hour average (ARM 17.8.752 and ARM 17.8.749).

c. MRL shall utilize an oxygen monitoring system and good combustion practices to minimize PM (ARM 17.8.752 and ARM 17.8.749).

d. H-4801 shall not combust PSA off-gas fuel containing H_2S in excess of 30 ppmv. Additionally, the heater shall not combust PSA off-gas fuel containing H_2S in excess of 10 ppmv on an annual average basis (ARM 17.8.752 and ARM 17.8.749).

e. H-4801 shall not combust RDU off-gas fuel containing H_2S in excess of 30 ppmv. Additionally, the heater shall not combust RDU off-gas in fuel containing H_2S in excess of 10 ppmv on an annual average basis (ARM 17.8.749 and ARM 17.8.752).

f. MRL shall utilize an oxygen monitoring system and good combustion practices to minimize VOCs (ARM 17.8.752 and ARM 17.8.749).

g. The annual average firing rate of H-4801 shall not exceed 213 MMBtu/hr (HHV) (ARM 17.8.749).

h. MRL shall comply with 40 CFR 63 Subpart DDDDD which requires the process heater to undergo a tune-up every five years, as specified in 40 CFR 63. 7540 (40 CFR 63, Subpart DDDDD, ARM 17.8.342 and ARM 17.8.749).

i. H-4801 shall only combust natural gas, PSA off-gas and RDU off-gas (ARM 17.8.749).

j. Opacity shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

4. New Tanks #301, #302, #303, #304, #305, #306, #307, #308, #309, #0801, and #4201

a. MRL shall control VOC emissions from Tank #301, #302, #303, #305, #306, #307, #308, #309 and #0801 by equipping each tank with a fixed roof and submerged fill design (ARM 17.8.752 and ARM 17.8.749).

b. MRL shall control VOC emissions from Tank #304 by equipping it with an external floating roof (ARM 17.8.752 and 40 CFR 60, Subpart Kb, ARM 17.8.340 and ARM 17.8.749).

c. MRL shall control VOC emissions from Tank #4201 by equipping it with a carbon adsorption control device (ARM 17.8.749 and ARM 17.8.752).

d. Tanks #301, #302 and #303 shall only be used to store renewable feed or an equivalent material with equal or lower vapor pressure (ARM 17.8.749).

e. Tank #304 shall only be used to store renewable naphtha or an equivalent material with equal or lower vapor pressure (ARM 17.8.749).

f. Tank #305 shall only be used to store renewable diesel or an equivalent material with equal or lower vapor pressure (ARM 17.8.749).

g. Tanks #306 and #307 shall only be used to store renewable kerosene or an equivalent material with equal or lower vapor pressure (ARM 17.8.749).

h. Tanks #308 and #309 shall only be used to store renewable kerosene or sustainable aviation fuel or an equivalent material with a vapor pressure equal or lower than the highest vapor pressure of renewable kerosene and sustainable aviation fuel (ARM 17.8.749).

i. Tank #0801 shall only be used to store conventional diesel (ARM 17.8.749).

j. Tank #4201 shall only be used to store wastewater produced by the PTU (ARM 17.8.749).

5. Hot Oil Expansion Tank (D-4203)

   MRL shall utilize proper equipment design and good operating practices to minimize VOCs from the Hot Oil Expansion Tank (D-4203) (ARM 17.8.752 and ARM 17.8.749).

6. PTU Blowdown Drum (D-4208)

   MRL shall utilize carbon adsorption for VOC control on the PTU Blowdown Drum (D-4208) (ARM 17.8.749 and ARM 17.8.752).

7. Tank #112 shall only be used to store renewable feed or RDU slop oil or an equivalent material with equal or lower vapor pressure (ARM 17.8.749).

8. Tanks #50 and #102 shall each be equipped with a fixed roof (ARM 17.8.752).

9. Tank #128 shall each be equipped with a fixed roof with pressure/vacuum vent and submerged fill (ARM 17.8.749 and ARM 17.8.752).

10. MRL shall utilize equipment design, and Leak Detection and Repair (LDAR) practices to control VOCs from the RDU, Hydrogen Plant #4, Storage Tanks, and PTU piping fugitive components, and PTU Wastewater Components (ARM 17.8.752 and ARM 17.8.749).

    a. RDU piping fugitive components "in VOC service" shall comply with the equipment leak provisions found in 40 CFR 60.482-1a through 60.482-10a. Pursuant to NESHAP Subpart FFFF, the RDU piping fugitive components "in organic HAP service" shall comply with the

new source equipment leak provisions found in 40 CFR 63.2480 (ARM 17.8.749).

b. Hydrogen Plant #4 piping fugitive components "in VOC service" shall comply with the equipment leak provisions found in 40 CFR 60.482-1a through 60.482-10a (ARM 17.8.749).

c. Storage Tank piping fugitive components "in VOC service" shall comply with the equipment leak provisions found in40 CFR 60.482-1a through 60.482.-10a. Pursuant to NESHAP Subpart FFFF, the Storage Tank piping fugitive components in "organic HAP service" shall comply with the new source equipment leak provisions found in 40 CFR 63.2480 (ARM 17.8.749).

d. PTU piping fugitive components "in VOC service" shall comply with the equipment leak provisions found in 40 CFR60.482-1a through 60.482-10a (ARM 17.8.749)

11. MRL shall follow the applicable requirements under 40 CFR 63, Subpart FFFF for all existing and new tanks depending upon whether each specific tank is in Group 1 or Group 2 (ARM 17.8.749, ARM 17.8.342 and 40 CFR 63, Subpart FFFF).

12. MRL shall utilize equipment design and equipment monitoring and maintenance practices to control VOCs from the RDU, Hydrogen Plant #4, Storage Tank, and PTU wastewater components (ARM 17.8.752 and ARM 17.8.749).

    a. RDU "individual drain systems," "oil-water separators," and "aggregate facilities" shall comply with the provisions found in 40 CFR 60.692–1 through 60.692–7. The RDU wastewater components shall comply with NESHAP Subpart FF and the wastewater provisions found in 40 CFR 63.2485 of NESHAP Subpart FFFF (ARM 17.8.749).

    b. Hydrogen Plant #4 "individual drain systems," "oil-water separators," and "aggregate facilities" shall comply with the provisions found in 40 CFR 60.692–1 through 60.692–7. The Hydrogen Plant #4 wastewater components shall comply with NESHAP Subpart FF (ARM 17.8.749).

    c. Storage Tank "individual drain systems," "oil-water separators," and "aggregate facilities" shall comply with the provisions found in 40 CFR 60.692–1 through 60.692–7. The Storage Tank wastewater components shall comply with NESHAP Subpart FF and the wastewater provisions found in 40 CFR 63.2485 of NESHAP Subpart FFFF (ARM 17.8.749).

    d. PTU "individual drain systems," "oil-water separators," and "aggregate facilities" shall comply with the provisions found in 40 CFR 60.692-1 through 60.692-7. The PTU wastewater components shall comply with NESHAP Subpart FF (ARM 1.8.749).

13. MRL shall comply with the emission control requirements of 40 CFR 63.2455 for each RDU Group 1 continuous process vent (40 CFR 63, Subpart FFFF, ARM 17.8.342 and ARM 17.8.749).

14. MRL shall comply with the monitoring requirements of 40 CFR 63.2455 for each applicable RDU Group 2 continuous process vent (40 CFR 63, Subpart FFFF, ARM 17.8.342 and ARM 17.8.749).

15. MRL shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any sources installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

16. MRL 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 (ARM 17.8.308).

17. MRL shall treat all unpaved portions of the access roads with water and/or chemical dust suppressant as necessary to maintain compliance with the reasonable precautions limitation in Section II.A.13 (ARM 17.8.749).

18. RDU Fractionator Feed Heater (H-4102)

    a. NOx emissions shall not exceed 0.04 lb/MMBtu (HHV) on a 1-hour average using ULNBs (ARM 17.8.752 and ARM 17.8.749).

    b. MRL shall use good combustion practices and an oxygen monitoring system to control CO emissions which may not exceed 0.055 lb/MMBtu (HHV) on a 1-hour average (ARM 17.8.752 and ARM 17.8.749).

    c. MRL shall utilize an oxygen monitoring system and good combustion practices to minimize PM (ARM 17.8.752 and ARM 17.8.749).

    d. PM (filterable) emissions shall not exceed 0.00051 lb/MMBtu (HHV) on a 1-hour average (ARM 17.8.752 and ARM 17.8.749).

    e. PM_{10} (filterable plus condensable) emissions shall not exceed 0.00051 lb/MMBtu (HHV) on a 1-hour average (ARM 17.8.752 and ARM 17.8.749).

    f. $PM_{2.5}$ (filterable plus condensable) emissions shall not exceed 0.00042 lb/MMBtu (HHV) on a 1-hour average (ARM 17.8.752 and ARM 17.8.749).

    g. MRL shall utilize an oxygen monitoring system and good combustion practices to minimize VOCs (ARM 17.8.752 and ARM 17.8.749).

    h. The annual average firing rate of H-4102 shall not exceed 30 MMBtu/hr (HHV) (ARM 17.8.749).

i. MRL shall conduct the work practice standards for minimizing CO and VOCs required under 40 CFR 63 Subpart DDDDD (40 CFR 63 Subpart DDDDD, ARM 17.8.749 and ARM 17.8.342).

j. H-4102 shall only combust pipeline quality natural gas and RDU off-gas (ARM 17.8.749).

k. H-4102 shall not combust RDU off-gas fuel containing H_2S in excess of 30 ppmv. Additionally, the heater shall not combust RDU off-gas fuel containing H_2S in excess of 10 ppmv on an annual average basis (ARM 17.8.749 and ARM 17.8.752).

l. Opacity shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304)

19. Hot Oil Heater (H-4201)

    a. NOx emissions shall not exceed 0.02 lb/MMBtu (HHV) on a 1-hour average using (ULNBs (ARM 17.8.752 and ARM 17.8.749).

    b. MRL shall use good combustion practices and an oxygen system to control CO emissions which may not exceed 0.04 lb/MMBtu (HHV) on a 1-hour average (ARM 17.8.752 and ARM 17.8.749).

    c. MRL shall utilize an oxygen monitoring system and good combustion practices to minimize PM (ARM 17.8.752 and ARM 17.8.749).

    d. MRL shall utilize an oxygen monitoring system and good combustion practices to minimize VOCs (ARM 17.8.752 and ARM 17.8.749).

    e. The annual average firing rate of H-4201 shall not exceed 38 MMBtu/hr (HHV) (ARM 17.8.752 and ARM 17.8.749).

    f. MRL shall conduct the work practice standards for minimizing CO and VOCs required under 40 CFR 63 Subpart DDDDD (40 CFR 63 Subpart DDDDD, ARM 17.8.749 and ARM 17.8.342).

    g. H-4201 shall only combust pipeline quality natural gas which is inherently low in sulfur (ARM 17.8.749 and Arm 17.8.752).

    h. Opacity shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304)

20. Railcar loading of renewable kerosene and sustainable aviation fuel shall utilize submerged fill loading (ARM 17.8.749 and ARM 17.8.752).

21. Truck loading and railcar loading of PTU wastewater shall utilize carbon adsorption to minimize VOC releases (ARM 17.8.749 and ARM 17.8.752).

B. Testing Requirements

1. The RDU Combined Feed Heater (H-4101) shall be tested for CO and NOx concurrently and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section II.A.1. The initial testing shall occur within 180 days of startup of the heater after it is transferred from Calumet Montana Refining, LLC (CMR) to MRL. Test procedures shall use EPA Reference Methods 10 and 7E or equivalent, as approved by the Department (ARM 17.8.105 and ARM 17.8.106).

2. The combined emissions from Hydrogen Plant #3 Reformer Heaters (H-3815A and H-3815B) shall be tested in the common stack for CO and NOx concurrently and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section II.A.2. The initial testing shall occur within 180 days of startup of the heaters after they are transferred from CMR to MRL. Test procedures shall use EPA Reference Methods 10 and 7E or equivalent, as approved by the Department (ARM 17.8.105 and ARM 17.8.106).

3. The Hydrogen Plant #4 Reformer Heater (H-4801) shall be tested for CO and NOx concurrently and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section II.A.3. The initial testing shall occur within 180 days of startup of the heater. Test procedures shall use EPA Reference Methods 10 and 7E or equivalent, as approved by the Department (ARM 17.8.105 and ARM 17.8.106).

4. The RDU Fractionator Feed Heater (H-4102) shall be tested for CO and NOx concurrently and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section II.A 17.a. The initial testing shall occur within 180 days of startup of the heater after it is transferred from CMR to MRL. Test procedures shall use EPA Reference Methods 10 and 7E or equivalent, as approved by the Department (ARM 17.8.105 and ARM 17.8.106).

5. The Hot Oil Heater (H-4201) shall be tested for CO and NOx concurrently and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section II.A.18.a. The initial testing shall occur within 180 days of startup of the heater. Test procedures shall use EPA Reference Methods 10 and 7E or equivalent, as approved by the Department (ARM 17.8.105 and ARM 17.8.106).

6. MRL shall sample and analyze the concentration (dry basis) of H_2S in the Hydrogen Plant #4 PSA off-gas fuel at least once per week, in order to demonstrate compliance with the limit in Section II.A.3.d (ARM 17.8.749).

7. MRL shall sample and analyze the concentration (dry basis) of H_2S in the RDU off-gas fuel at least once per month in order to demonstrate compliance with the limit in Section II.A.1.k, II.A.3.e, and II.A.17.k.

8. The NOx and O_2 CEMS on the RDU Combined Feed Heater (H-4101), Hydrogen Plant #3 Reformer Heaters (H-31815A/H-3815B), and Hydrogen

Plant #4 Reformer Heater (H-4801) shall comply with 40 CFR 60.13- 60.19 Subpart A—General Provisions and 40 CFR 60 Appendices B and F (ARM 17.8.749).

9. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

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

C. Operational Reporting Requirements

1. MRL shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information may be used to calculate operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. MRL shall document, by month, the total MMBtu's combusted for each of the heaters (RDU Combined Feed Heater (H-4101), Hydrogen Plant #3 Reformer Heaters (H-3815A and H-3815B), Hydrogen Plant #4 Reformer Heater (H-4801), RDU Fractionator Feed Heater (H-4102), and Hot Oil Heater (H-4201), and apply the appropriate emission factors on a lb/MMBtu basis to calculate the monthly emissions. The monthly emissions information for the calendar year shall be submitted annually to the Department along with the annual emission inventory (ARM 17.8.749).

3. MRL shall notify the Department of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include ***the addition of a new emissions unit,*** 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. The notice must be submitted to the Department, in writing, 10 days prior to startup 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(l)(d) (ARM 17.8.745).

4. All records compiled in accordance with this permit must be maintained by MRL as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request. These records may be stored at a location other than the plant site upon approval by the Department (ARM 17.8.749).

D. Notification

MRL shall provide the Department with written notification of the following information within the specified time periods (ARM 17.8.749):

1. Startup date of the RDU Combined Feed Heater (H-4101) after it is transferred from CMR to MRL within 15 working days of the start-up date.

2. Startup date of the Hydrogen Plant #4 Reformer Heater (H-4801) within 15 working days of the startup date.

3. Startup date of the RDU Fractionator Feed Heater (H-4102) after it is transferred from CMR to MRL within 15 working days of the start-up date.

4. Startup date of the Hot Oil Heater (H-4201) within 15 working days of the startup date.

5. Startup dates of each of the new tanks #301, #302, #303, #304 #305, #306, #307, #308, #309, #0801, and #4201 within 15 working days of the startup date of each tank.

6. Date of transfer of Hydrogen Plant #3 from CMR to MRL and dates of transfer of each of the existing tanks (#29, #50, #102, #112, #116, #128 and #140) from CMR to MRL within 15 working days of transfer of each.

SECTION III: General Conditions

A. Inspection – MRL shall allow the Department's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment such as Continuous Emission Monitoring Systems (CEMS) or Continuous Emission Rate Monitoring Systems (CERMS), or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

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

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving MRL 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 action as specified in Section 75-2-401, *et seq.*, MCA.

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefor, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the

Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

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

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

H. 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).

Montana Air Quality Permit (MAQP) Analysis
Montana Renewables LLC.
MAQP #5263-01

I. Introduction/Process Description

A. Permitted Equipment

Pretreatment Unit (PTU) including

- Deaerator, liquid-liquid separator, and blowdown process vessels
- Liquid reactors
- Heat exchangers
- Filters and static mixers; and
- Piping and piping components (pumps, valves, flanges, connectors, etc.).

Hot Oil System including:

- Hot Oil Heater (H-4201)
- Hot Oil Expansion Tank (D-4203)

PTU Wastewater Handling including:

- Tank #4201
- Truck loading facility and
- Railcar loading facility (or use of existing railcar loading infrastructure transferred from Calumet Montana Refining, LLC (CMR) to Montana Renewables, LLC (MRL).

Railcar Unloading of Renewable Feedstock

Railcar Loading of Renewable Diesel, Renewable Kerosene, and Sustainable Aviation Fuel

Equipment previously permitted under MAQP #5263-00 and changes to the original project design including other new equipment is noted below:

Hydrogen Plant #4 will be installed at the MRL plant to supply hydrogen feedstock to the Renewable Diesel Unit (RDU)

- Hydrogen Plant #4 Reformer Heater (H-4801)
- Piping fugitive components and
- Wastewater components

New Tanks storing either renewable feed or renewable fuels

- Tank #301
- Tank #302
- Tank #303
- Tank #304
- Tank #305

MRL also proposes to receive, refurbish as necessary, and operate the following existing equipment transferred from CMR

RDU Combined Feed Heater (H-4101)

Hydrogen Plant #3: (including Hydrogen Plant #3 Reformer Heaters H-3815A and H-3815B given new emitting unit numbers).

MHC Fractionator Feed Heater (H-4102) (Now RDU Fractionator Feed Heater H-4102)

Tanks

- Tank #29
- Tank #50
- Tank #102
- Tank #112
- Tank #116
- Tank #128 and
- Tank #140

Associated piping, valves, pumps and supporting equipment.

The plant will also share some connectivity with flaring devices, material unloading and loading facilities, utility systems (e.g., steam and cooling water), and wastewater treatment systems owned and operated by CMR. These are further described in the permit analysis.

Existing and new equipment elated to Renewable Kerosene and Sustainable Aviation Fuel Production and other Design Changes.

Existing RDU side stripper for renewable kerosene production.

New piping (pumps, valves, flanges, connectors) and heat exchanger to handle and cool renewable kerosene.

New process vessels in the RDU to perform filtration, coalescence and drying of renewable kerosene.

Four new tanks to store renewable kerosene and sustainable aviation fuel (SAF)
- Tank #306 for storing renewable kerosene
- Tank #307 for storing renewable kerosene
- Tank #308 for storing renewable kerosene or sustainable aviation fuel
- Tank #309 for storing renewable kerosene or sustainable aviation fuel

Tank #0801 for storing conventional diesel which will be blended with renewable diesel during railcar loading operations.

B. Source Description

The equipment described above will operate at the MRL Great Falls Renewable Fuels Plant, which will be adjacent to the CMR Great Falls Refinery. MRL will operate as a

subsidiary to Calumet Specialty Products Partners, L.P., as does CMR. The equipment operating at the project site will not be a petroleum refinery and the numerous regulatory requirements for petroleum refineries will not apply to any of the new or transferred equipment operating under MAQP #5263-01. The renewable fuel products, including sustainable aviation fuel that is produced will be marketed into Canadian and West Coast U.S. markets.

C. Response to Public Comments

Comments received from Montana Renewables

PD Section Referenced	Comment	DEQ Response
Section II.A.1.b	Add "monitoring" to oxygen system description	Modified as requested
Section II.A.1.k	Separate the two conditions to read "H-4101 shall not combust RDU off-gas fuel containing H_2S in excess of 30 ppmv. Additionally, the heater shall not combust RDU off-gas fuel containing H_2S in excess of 100 ppmv on an annual average basis."	Modified as requested
Section II.A.2.c	Spell out filterable and condensable where they were previously abbreviated. For this condition and any other in the PD.	Modified as requested
Section II.A.2.c.i-iii	Add "on a 1-hour average" to each of these three conditions	Modified as requested
Section II.A.3.e	Separate the two conditions to read "H-4801 shall not combust RDU off-gas fuel containing H_2S in excess of 30 ppmv. Additionally, the heater shall not combust RDU off-gas fuel containing H_2S in excess of 100 ppmv on an annual average basis."	Modified as requested
Section II.A.3.g	Modify condition to read "The annual average firing rate…"	Modified as requested
Section II.A.4	Delete description: "For renewable feed, renewable fuels, naphtha, kerosene, sustainable aviation fuel or RDU slop oil" as the sub-conditions identify materials to be stored	Modified as requested
Section II.A.4.d	Add Tank #303 to this condition	Modified as requested
Section II.A.4.i	Remove renewable kerosene as this tank will only store conventional diesel	Modified as requested
Section II.A.9	Clarify condition to read "PUT piping fugitive components"	Modified as requested

Section II.A.9.d	Add new condition "PTU piping fugitive components "in VOC service" shall comply with the equipment leak provisions found in 40 CFR 60.482-1a through 60.482-10a."	Modified as requested
Section II.A.11	Insert "and PTU" before wastewater components	Modified as requested
Section II.A.11	Add new condition "PTU "individual drain systems," "oil-water separators," and "aggregate facilities" shall comply with the provisions found in 40 CFR 60.692–1 through 60.692–7. The PTU wastewater components shall comply with NESHAP Subpart FF."	Modified as requested
Section II.A.17.a	Modify condition to read "NOx emissions shall not exceed 0.04 lb/MMBtu (Higher Heating Value) (HHV) on a 1-hour average using ULNBs."	Modified as requested
Section II.A.17.k	Modify conditions to read "H-4102 shall not combust RDU off-gas fuel containing H2S in excess of 30 ppmv. Additionally, the heater shall not combust RDU off-gas fuel containing H2S in excess of H2S and 10 ppmv on an annual average basis."	Modified as requested
Section II.A.18.a	Modify condition to read "NOx emissions shall not exceed 0.02 lb/MMBtu (HHV) on a 1-hour average using (ULNBs)."	Modified as requested
Section II.B.2	Modify this condition to make it consistent with the timing of other heaters that are being transferred from CMR to MRL.	Modified as requested
Section II.B.7	Modify this condition to read "MRL shall sample and analyze the concentration (dry basis) of H2S at least once per month in order to demonstrate compliance with the limits in Section II.A.1.k, II.A.3.e., and II.A17.k."	Modified as requested
Section II.A.D	Modify condition to read "Date of transfer of Hydrogen Plant #3 from CMR to MRL and dates of transfer of each of the existing tanks (#29, #50, #102, #112, #116, #128 and #140) from CMR to MRL within 15 working days of transfer of each."	Modified as requested

Permit Analysis: Section II.C.8	Add new condition that H-4201 will be subject to Subpart Dc	Modified as requested
Environmental Analysis	Minor text changes were made to the EA including identifying the facility name as MRL Great Falls Renewable Fuels Plant	Modified as requested

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 Administrative Rules of Montana (ARM) and are available, upon request, from the Department of Environmental Quality (Department). Upon request, the Department will provide references for location of complete copies of all applicable rules and regulations or copies where appropriate.

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

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

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

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

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

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

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction of 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 as to create a public nuisance.

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

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 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
8. ARM 17.8.221 Ambient Air Quality Standard for Visibility
9. ARM 17.8.222 Ambient Air Quality Standard for Lead
10. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}
11. ARM 17.8.230 Fluoride in Forage

MRL must maintain compliance with the applicable ambient air quality standards.

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 into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

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, MRL 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. Sulfur Oxide Emissions-Sulfur in Fuel. 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.

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, Standards of Performance for New Stationary Sources (NSPS). MRL is considered an NSPS affected facility under 40 CFR Part 60 (portions of the transferred and shared equipment was already subject) and is subject to the requirements of the following subparts.

   a. 40 CFR 60, Subpart A – General Provisions apply to all equipment or facilities subject to an NSPS Subpart as listed below:

   b. 40 CFR 60, Subpart D_C – Standards of Performance for Small Industrial-Commercial Institutional Steam Generating Units.

   c. 40 CFR 60, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984.

9. ARM 17.8.341 Emission Standards for Hazardous Air Pollutants. This source shall comply with the standards and provisions of 40 CFR Part 61, as appropriate.

   a. 40 CFR 61, Subpart A – General Provisions apply to all equipment or facilities subject to a NESHAP Subpart as listed below:

   b. 40 CFR 61, Subpart M – National Emission Standard for Asbestos. Any demolition occurring would fall under this subpart as applicable.

   c. 40 CFR 61, Subpart FF – National Emission Standard for Benzene Waste Operations

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. 40 CFR 63, Subpart A – General Provisions apply to all equipment or facilities subject to a NESHAP Subpart as listed below:

    b. 40 CFR 63, Subpart FFFF – National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing

c. 40 CFR 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

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. MRL 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 the Department. MRL submitted the appropriate permit application fee for the current permit action.

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

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

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

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

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify, or use any air contaminant sources that have the potential to emit (PTE) greater than 25 tons per year of any pollutant. MRL has a PTE greater than 25 tons per year of NOx, CO and VOCs, 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. MRL submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. MRL submitted an affidavit of publication of public notice for May 19, 2022, May 26, 2022, and June 2, 2002, in the Great Falls Tribune, as proof of compliance with the public notice requirements.

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

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

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

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

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

11. ARM 17.8.760 Additional Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those applications that require an environmental impact statement.

12. 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.

13. 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).

14. 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 17.8.752, 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.

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

16. ARM 17.8.770 Additional Requirements for Incinerators. This rule specifies the additional information that must be submitted to the Department for incineration facilities subject to 75-2-215, Montana Code Annotated (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.

This facility is not a major stationary source because although the facility is a listed source its PTE is below 100 tons per year for all non-greenhouse gas pollutants.

H. ARM 17.8.1204 Air Quality Operating Permit Program. (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 #5263-01 for MRL, the following conclusions were made:

a. The facility's PTE is less than 100 tons/year for non-greenhouse gas pollutants.

b. The facility's PTE, in combination with the CMR Great Falls Refinery's PTE is greater than 10 tons/year for any one HAP and greater than 25 tons/year for all HAPs.

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

d. This facility is subject to NSPS 40 CFR 60, Subpart A, Subpart Dc, and Subpart Kb.

e. This facility is subject to NESHAP 40 CFR 63, Subpart A, Subpart FFFF and Subpart DDDDD.

f. This source is not a Title IV affected source, or a solid waste combustion unit.

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

Based on these facts, the Department determined that MRL is subject to the Title V operating permit program. Since there is common ownership and adjacent/contiguous property, Title V applicability is assumed as long as the current ownership structure exists.

III. BACT Determination

A BACT determination is required for each new or modified source. MRL 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.

The BACT determination summary is presented directly below. The individual BACT evaluations for all emitting units by pollutant is included below the summary table.

Emissions Unit	Pollutant	Control Technology/ Work Practice	Emissions Level
RDU Fractionator Feed Heater (H-4102)	CO	Good Combustion Practices	0.055 lb/MMBtu (Higher Heating Value (HHV))
			(1-hour average)
	NOx	ULNBs	0.04 lb/MMBtu (HHV) (1-hour average)
	PM	Good Combustion Practices	0.00051 lb/MMBtu (HHV)
	(filt.)		(1-hour average)
	PM_{10}	Good Combustion Practices	0.00051 lb/MMBtu (HHV)
	(filt. + cond.)		(1-hour average)
	$PM_{2.5}$	Good Combustion Practices	0.00042 lb/MMBtu (HHV)
	(filt. + cond.)		(1-hour average)
	SO_2	Low Sulfur Gaseous Fuel	Fuel gas containing ≤30 ppmv H_2S and ≤10 ppmv H_2S on an annual average basis
	VOC	Good Combustion Practices	-
Hot Oil Heater (H- 4201)	CO	Good Combustion Practices	0.04 lb/MMBtu (HHV) (1-hour average)
	NOx	ULNBs	0.02 lb/MMBtu (HHV) (1-hour average)
	PM	Good Combustion Practices	-
	(filt.)		
	PM_{10}	Good Combustion Practices	-
	(filt. + cond.)		
	$PM_{2.5}$	Good Combustion Practices	-
	(filt. + cond.)		
	SO_2	Low Sulfur Gaseous Fuel (Pipeline Quality Natural Gas)	-
	VOC	Good Combustion Practices	-
Tank #306	VOC	Fixed Roof with Submerged Fill	-
Tank #307	VOC	Fixed Roof with Submerged Fill	-
Tank #308	VOC	Fixed Roof with Submerged Fill	-
Tank #309	VOC	Fixed Roof with Submerged Fill	-
Tank #0801	VOC	Fixed Roof with Submerged Fill	-
Tank #4201	VOC	Carbon Adsorption	-
Hot Oil Expansion Tank (D-4203)	VOC	Proper Equipment Design and Operating Practices	-
PTU Blowdown Drum (D-4208)	VOC	Carbon Adsorption	-
PTU Piping Fugitive Components	VOC	Equipment Design and LDAR	-
PTU Wastewater Components	VOC	Equipment Design, Monitoring, and Maintenance	-
Loading - Renewable Kerosene/Sustainable Aviation Fuel			
	VOC	Submerged Fill Loading	-
Loading - PTU Wastewater	VOC	Carbon Adsorption	-

RDU Fractionator Feed Heater (H-4102)

Carbon Monoxide (CO)

Step 1: Identify Control Technologies

Good Combustion Practices

Good combustion practices for a gaseous fuel enclosed combustion device provide a properly set and controlled air-to-fuel ratio and appropriate combustion zone residence time, temperature, and turbulence parameters essential to achieving low CO emission levels. Incomplete combustion of fuel hydrocarbons can occur because of improper combustion mechanisms, which may result from poor burner/combustion device design, operation, and/or maintenance. However, a heater is designed and typically operated to maximize fuel combustion efficiency so that its fuel usage cost is minimized while maximizing process heating performance. Good combustion practices can be achieved by following a combustion device manufacturer's operating procedures and guidelines, as well as complying with NESHAP Subpart DDDDD work practice standards, which require a combustion device to undergo regular tune-ups.

Thermal Oxidation

Thermal oxidation can be used to reduce CO contained in a source's exhaust stream by maintaining the stream at a high enough temperature in the presence of oxygen, resulting in the oxidation of CO to CO_2. Thermal oxidation of a CO exhaust stream can be achieved by routing the stream to a flare, afterburner, or thermal oxidizer. The effectiveness of all thermal oxidation processes is influenced by residence time, turbulence, and temperature. Auxiliary fuel is typically required to achieve the temperature needed to ensure proper CO exhaust stream oxidation in a thermal oxidation process. If additional fuel is present in the feed stream, some oxidizers are self-sustaining and do not require additional fuel. The necessary amount of auxiliary fuel is dependent on the CO content of the exhaust stream, as well as the amount of hydrocarbon that may be present in the exhaust stream.

Catalytic Oxidation

Catalytic oxidation makes use of catalysts, using precious metals platinum, palladium, or rhodium, to reduce the temperature at which CO oxidizes to CO_2. The effectiveness of catalytic oxidation is dependent on the exhaust stream temperature and the presence of potentially poisoning contaminants in the exhaust stream. The amount of catalyst volume is dependent upon the exhaust stream flow rate, CO content, and temperature, as well as the desired CO removal efficiency. The catalyst will experience activity loss over time due to physical deterioration and/or chemical deactivation. Therefore, periodic testing of the catalyst is necessary to monitor its activity (i.e., oxidation promoting effectiveness) and predict its remaining life. As needed, the catalyst will require periodic replacement. Catalyst life varies from manufacturer-to manufacturer, but three to six-year windows are not uncommon.

Step 2: Eliminate Technically Feasible Options

Good Combustion Practices

Good combustion practices are an integral component of the design and operation of the heater. Therefore, this option is technically feasible for the heater.

Thermal Oxidation

Thermal oxidation is not technically feasible for the control of CO emissions from the heater due to the very low concentration of CO in its exhaust stream. The application of thermal oxidation to reduce the heater's CO emission rate would require the combustion of a considerable amount of fuel to achieve the elevated temperature necessary to promote the oxidation of the small amount of CO that will be present in the heater's exhaust stream. This fuel combustion would generate additional combustion pollutants, including CO. Thus, the CO emission reduction effectiveness of the thermal oxidation system would be reduced, if not negated, because of the CO generated by the thermal oxidation process.
In summary, the addition of a second thermal oxidation process to the heater system may not reduce the heater's CO emissions by any appreciable amount, if at all, and this add-on control technology would considerably increase the energy requirements of the heater system while notably increasing the amount of combustion pollutants, such as NOx and CO_2, emitted into the atmosphere. Furthermore, research of emission control technology application data (i.e., EPA's Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database) indicates thermal oxidation has not been used to control CO emissions from a comparable heater. Based on these factors, MRL determined that it is not technically feasible to use thermal oxidation on this heater to control the heater's CO emissions.

Catalytic Oxidation

Catalytic oxidation is not technically feasible for the control of CO emissions from the heater because its exhaust gas temperature is too low for the effective operation of the oxidation catalyst. The optimum temperature range for catalytic oxidation is 850 to 1,100°F. Below temperatures of 500 to 600°F, the CO removal efficiency of the oxidation catalyst is considerably reduced. The heater's convection section incorporates heat recovery to heat a process stream in a set of coils. Specifically, the convection section incorporates a feed preheat coil. The exhaust gas temperature after this heat recovery operation is too low for the effective operation of catalytic oxidation. Moreover, due to the considerably low concentration of CO in the heater's exhaust stream, the potential effectiveness of a catalytic oxidation system in this case would be limited.

Step 3: Rank Remaining Control Technologies

The only remaining available CO emission control technology for the RDU Fractionator Feed Heater (H-4102) is good combustion practices.

Step 4: Evaluate Most Effective Control Options

The only remaining available CO emission control technology for the RDU Fractionator Feed Heater (H-4102) is good combustion practices.

Step 5: Select BACT

MRL determined that good combustion practices represent the maximum air pollution control capability for CO emissions from the RDU Fractionator Feed Heater (H-4102).

Therefore, MRL will control CO emissions from the heater by using good combustion

practices and complying with the following emission limitation: CO emissions from the RDU Fractionator Feed Heater (H-4102) shall not exceed 0.055 lb/MMBtu (HHV), based on a 1-hour average.

NOx

The RDU Fractionator Feed Heater (H-4102) will emit NOx, primarily due to the "thermal" and "prompt" NOx generation mechanisms because the heater's fuel will not contain appreciable amounts of organo-nitrogen compounds that result in "fuel" NOx emissions. Thermal NOx results from the high temperature thermal dissociation and subsequent reaction of combustion air molecular nitrogen and oxygen, and it tends to be generated in the high temperature zone near the burner of an external combustion device. The rate of thermal NOx generation is affected by the following three factors: oxygen concentration, peak flame temperature, and duration at peak flame temperature. As these three factors increase in value, the rate of thermal NOx generation increases.

Prompt NOx occurs at the flame front through the relatively fast reaction between combustion air nitrogen and oxygen molecules and fuel hydrocarbon radicals, which are intermediate species formed during the combustion process. Prompt NOx may represent a meaningful portion of the NOx emissions resulting from low NOx burners (LNBs) and ultra low NOx burners (ULNBs).The heater will not be subject to an NSPS NOx emission standard after the proposed change in its operation. However, the heater was previously subject to a BACT requirement (ARM 17.8.752) of 0.040 lb/MMBtu (HHV) based on a 3-hour average.

Step 1: Identify Control Technologies

Low NOx Burners, Ultra Low NOx Burners (LNBs/ULNBs)

LNBs/ULNBs are available in a variety of configurations and burner types, and they may incorporate one or more of the following concepts: lower flame temperatures; fuel rich conditions at the maximum flame temperature; and decreased residence times for oxidation conditions. These burners are often designed so that fuel and air are pre-mixed prior to combustion, resulting in lower and more uniform flame temperatures. Pre-mix burners may require the aid of a blower to mix the fuel with air before combustion takes place. Additionally, an LNB/ULNB may be designed so that a portion of a combustion device's flue gas is recycled back into the burner in order to reduce the burner's flame temperature. However, instead of recycled flue gas, steam can also be used to reduce a burner's flame temperature. Furthermore, LNBs/ULNBs may use staged combustion, which involves creating a fuel rich zone to start combustion and stabilize a burner's flame, followed by a fuel lean zone to complete combustion and reduce the burner's peak flame temperature.

Selective Catalytic Reduction (SCR)

SCR is a post-combustion treatment technology that promotes the selective catalytic chemical reduction of NOx (both nitric oxide and nitrogen dioxide) to molecular nitrogen and water. SCR technology involves the mixing of a reducing agent (aqueous or anhydrous ammonia or urea) with NOx-containing combustion gases and the resulting mixture is passed through a catalyst bed, where the catalyst serves to lower the activation energy of the NOx reduction reactions. In the catalyst bed, the NOx and ammonia contained in the combustion gas-reagent mixture are adsorbed onto the SCR catalyst surface to form an

activated complex and then the catalytic reduction of NOx occurs, resulting in the production of nitrogen and water from NOx. The nitrogen and water products of the SCR reaction are desorbed from the catalyst surface into the combustion exhaust gas passing through the catalyst bed. From the SCR catalyst bed, the treated combustion exhaust gas is emitted to the atmosphere. SCR systems can effectively operate at a temperature above 350°F and below 1,100°F, with a more refined temperature window dependent on the composition of the catalyst used in the SCR system.

Selective Non-catalytic Reduction (SNCR)
SNCR is a post-combustion treatment technology that is effectively a partial SCR system. A reducing agent (aqueous or anhydrous ammonia or urea) is mixed with NOx-containing combustion gases and a portion of the NOx reacts with the reducing agent to form molecular nitrogen and water. As indicated by the name of this technology, SNCR unlike SCR does not utilize a catalyst to promote the chemical reduction of NOx.

Because a catalyst is not used with SNCR, the NOx reduction reactions occur at high temperatures. SNCR typically requires thorough mixing of the reagent in the combustion chamber of an external combustion device because this technology requires at least 0.5 seconds of residence time at a temperature above 1,600°F and below 2,100°F. A combustion device equipped with SNCR technology may require multiple reagent injection locations because the optimum location (temperature profile) for reagent injection may change depending on the load at which the combustion device is operating. At temperatures below 1,600°F, the desired NOx reduction reactions will not effectively occur and much of the injected reagent will be emitted to the atmosphere along with the mostly uncontrolled NOx emissions. At temperatures above 2,100°F, the desired NOx reduction reactions will not effectively occur, and the ammonia or urea reagent will begin to react with available oxygen to produce additional NOx emissions.

Non-Selective Catalytic Reduction (NSCR)

NSCR is a post-combustion treatment technology that promotes the catalytic chemical reduction of NOx (both nitric oxide and nitrogen dioxide) to molecular nitrogen and water. NSCR technology has been applied to nitric acid plants and rich burn and stoichiometric internal combustion engines to reduce NOx emissions. NSCR technology uses a reducing agent (hydrocarbon, hydrogen, or CO), which can be inherently contained in the exhaust gas due to rich combustion conditions or injected into the exhaust gas, to react in the presence of a catalyst with a portion of the NOx contained in the source's exhaust gas to generate molecular nitrogen and water. NSCR systems can effectively operate at a temperature above 725°F and below 1,200°F, with a more refined temperature window dependent on the source type and composition of the catalyst used in the NSCR system.

Step 2: Eliminate Technically Infeasible Options

LNBs/ULNBs
The heater is already equipped with ULNBs. Therefore, this option is technically feasible and was incorporated into the baseline emissions for the heater.

SCR

This option is technically feasible for the heater.

SNCR

Due to the temperature and mixing profile sensitivities of an SNCR system, these systems often have not achieved the expected amounts of theoretical NOx emission reduction, especially in turndown modes of operation. However, MRL conservatively estimated SNCR is technically feasible to control the heater's NOx emissions.

NSCR

NSCR technology is not technically feasible for the control of NOx emissions from the heater because it does not operate at the 0.5% or less excess oxygen concentration necessary to ensure NOx reduction with NSCR. Instead, the heater operates with an excess oxygen concentration of approximately 2-3%. This amount of excess oxygen promotes both low levels of CO and high combustion (thermal) efficiency, while also providing for safe heater operations during variations in fuel gas operating conditions (e.g., fuel gas composition changes, fuel gas supply pressure variations). Furthermore, research of EPA's RBLC database indicates NSCR has not been used to control NOx emissions from a comparable heater. These factors indicate it is not technically feasible to use NSCR to control the heater's NOx emissions.

Step 3: Rank Remaining Control Technologies

The remaining available NOx emission control technologies for the RDU Fractionator Feed Heater (H-4102) are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions.

SCR
SNCR
ULNBs: this control technology was incorporated into the emissions unit's baseline emissions because the unit is already equipped with ULNBs.

Step 4: Evaluate Most Effective Control Options

SCR

MRL estimated that the installation and operation of an SCR system on the heater would result in a cost effectiveness equal to approximately $43,699 per ton of NOx emission reduction, which is not cost effective. Also, the installation of an SCR system on the heater would require additional energy to operate the SCR system's electrical equipment (e.g., pumps, heaters/vaporizers, instrumentation) and provide fan
power to overcome the pressure drop across the SCR catalyst bed(s). This increase in electricity usage at the plant would generate emissions at the power plants generating the electricity thus reducing the net environmental benefit of the SCR system. Furthermore, the SCR catalyst would require periodic replacement, which would result in a spent catalyst waste stream. This waste stream may represent hazardous waste depending on the composition of the catalyst and the heater's combustion products collected on the catalyst.

An SCR system would also cause ammonia slip during operation, resulting in ammonia emissions from the heater's stack, which may negatively impact regional haze due to an increase in the amount

of atmospheric ammonia available to generate visibility impairing ammonium nitrates and ammonium sulfates.

In summary, MRL determined that it would not be cost effective to equip the heater with an SCR system, and the operation of an SCR system on the heater would likely result in additional emissions, as well as the generation of an additional solid waste stream at the site. For these reasons, MRL eliminated an SCR system from consideration as the maximum air pollution control capability for the heater's NOx emissions.

SNCR

MRL estimated that the installation and operation of an SNCR system on the heater would result in a cost effectiveness equal to approximately $31,752 per ton of NOx emission reduction, which is not cost effective. The installation of an SNCR system on the heater would require additional energy to operate the SNCR system's electrical equipment (e.g., pumps, heaters/vaporizers, instrumentation). This increase in electricity usage at the site would generate emissions at the power plants generating the electricity thus reducing the net environmental benefit of the SNCR system. Furthermore, an SNCR system would experience ammonia slip during operation, resulting in ammonia emissions from the heater's stack, which may negatively impact regional haze due to an increase in the amount of atmospheric ammonia available to generate visibility impairing ammonium nitrates and ammonium sulfates.

In summary, MRL determined that it would not be cost effective to equip the heater with an SNCR system, and the operation of an SNCR system on the heater would likely result in additional emissions. For these reasons, MRL eliminated an SNCR system from consideration as the maximum air pollution control capability for the heater's NOx emissions.

Step 5: Select BACT

MRL determined that ULNBs represent the maximum air pollution control capability for the NOx emissions from the RDU Fractionator Feed Heater (H-4102). The heater is already equipped with ULNBs and MRL will continue to comply with the following emission limitation that was previously determined to reflect the BACT for this unit where NOx emissions from the RDU Fractionator Feed Heater (H-4102) shall not exceed 0.04 lb/MMBtu (HHV), based on a 1-hour average.

$PM/PM_{10}/PM_{2.5}$

The RDU Fractionator Feed Heater (H-4102) will emit PM_{10} and $PM_{2.5}$ comprised of filterable and condensable portions. A gaseous fuel combustion device can emit PM_{10} and $PM_{2.5}$ at elevated levels due to the incomplete combustion of higher molecular weight hydrocarbons present in the device's gaseous fuel. However, the heater will combust pipeline quality natural gas and RDU off-gas, which are primarily comprised of hydrogen and relatively low molecular weight hydrocarbons. Therefore, elevated PM_{10} and $PM_{2.5}$ emissions from the heater as a result of the incomplete combustion of high molecular weight hydrocarbons are not expected to occur. Additionally, the referenced fuels will contain low levels of sulfur, further minimizing the generation of PM_{10} and $PM_{2.5}$ when they are combusted.

The heater is not currently subject to an NSPS or NESHAP PM, PM_{10}, or $PM_{2.5}$ emission standard, and it will not be subject to an NSPS or NESHAP PM, PM_{10}, or $PM_{2.5}$ emission standard after the proposed change in its operation. However, the heater is subject to the

following DEQ opacity and BACT limits for PM, PM_{10}, and $PM_{2.5}$ standards:

Pursuant to ARM 17.8.304(2), emissions from the heater shall not exceed an opacity of 20% or greater averaged over six consecutive minutes.

Pursuant to ARM 17.8.752, PM emissions from the heater shall not exceed 0.00051 lb/MMBtu.

Pursuant to ARM 17.8.752, PM_{10} emissions from the heater shall not exceed 0.00051 lb/MMBtu.

Pursuant to ARM 17.8.752, $PM_{2.5}$ emissions from the heater shall not exceed 0.00042 lb/MMBtu.

Step 1: Identify Control Technologies

Good Combustion Practices
Electrostatic Precipitator
Filter
Wet Scrubber
Cyclone
Good Combustion Practices – See description of Good Combustion practices on page 11.

Electrostatic Precipitator (ESP)

An ESP uses an electric field and collection plates to remove PM from a flowing gaseous stream. The PM contained in the gaseous stream is given an electric charge by passing the stream through a corona discharge. The resulting negatively charged PM is collected on the flowing gaseous stream that is being treated by the ESP. In a dry ESP, the collection plate cleaning process can be accomplished mechanically by knocking the PM loose from the plates. Alternatively, in a wet ESP, a washing technique is used to remove the collected PM from the collection plates. ESPs can be configured in several ways, including a plate-wire ESP, a flat-plate ESP, and a tubular ESP. As the diameter of the PM decreases, the efficiency of an ESP decreases.

Filter

A filter is a porous media that removes PM from a gaseous stream as the stream passes through the filter. For an emissions unit with an appreciable exhaust rate, the filter system typically contains multiple filter elements. Filters can be used to treat exhaust streams containing dry or liquid PM.

Filters handling dry PM become coated with collected PM during operation and this coating ("cake") contributes to the filtration mechanism. A dry PM filter system commonly used in industrial scale applications is a "baghouse." A baghouse is comprised of multiple cylindrical bags, and the number of bags is dependent on the exhaust rate requiring treatment, the PM loading of the exhaust stream, and the baghouse design. The two most common baghouse designs today are the reverse-air and pulse-jet designs. These design references indicate the type of bag cleaning system used in the baghouse.

Filters handling liquid PM rely on the impingement of the entrained liquid PM on the surface

of the filter media and the retention of these liquid particles on the surface until multiple particles coalesce into particles of sufficient size that are able to fall back against the flowing gas stream and collect at a location below the filter. For the high efficiency removal of submicron liquid particles from a gaseous stream, Brownian diffusion filters are used. "Brownian diffusion" is the random movement of submicron particles in a gaseous stream as these particles collide with gas molecules. Liquid PM filter systems can be comprised of pad or candle filter elements. These filter elements require little operation and maintenance attention.

Wet Scrubber

Wet scrubber uses absorption to remove PM from a gaseous stream. Absorption is primarily a physical process, though it can also include a chemical component, in which a pollutant in a gas phase contacts a scrubbing liquid and is dissolved in the liquid. A key factor dictating the performance of a wet scrubber is the solubility of the pollutant of concern in the scrubbing liquid. Water is commonly used as the scrubbing liquid in a wet scrubber used for PM emission control, but other liquids can be used depending on the type of PM or other pollutant(s) to be removed from the gaseous stream undergoing treatment. There are several types of wet scrubbers, including packed-bed counterflow scrubbers, packed-bed cross-flow scrubbers, bubble plate scrubbers, and tray scrubbers.

Cyclone

A cyclone is the most common type of inertial separator used to collect medium-sized and coarse PM from gaseous streams. The PM contained in a gaseous stream treated in a cyclone moves outward under the influence of centrifugal force until it contacts the wall of the cyclone. The PM is then carried downward by gravity along the wall of the cyclone and collected in a hopper located at the bottom of the cyclone. Although cyclones provide a relatively low cost, mechanically simple option for the removal of larger diameter PM from gaseous streams, alone they do not typically provide adequate PM removal, especially when the gaseous stream contains smaller diameter PM. Instead, these devices are typically used to preclean a gaseous stream by removing larger diameter PM upstream of PM emission control devices that are more effective at removing smaller diameter PM.

Step 2: Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices are already an integral component of the design and operation of the heater. Therefore, this option is technically feasible for the heater.

ESP

MRL estimated that the PM emitted by the heater will be PM_{10} only, which is a characteristic that would limit the control effectiveness of an ESP. Additionally, the PM_{10} concentration in the heater's exhaust stream is below the concentration typically seen in an ESP's exhaust stream. Thus, an ESP would not lower the heater's PM_{10} emissions by any appreciable amount. Furthermore, research of EPA's RBLC database indicates an ESP has not been used to control PM emissions from a comparable heater. These factors indicate it would not be technically feasible to use an ESP to control PM emissions from the heater.

Filter

The PM_{10}-only profile of the heater's PM emissions would limit the control effectiveness of a filter. Additionally, the PM_{10} concentration in the heater's exhaust stream is below the concentration typically seen in a filter's exhaust stream. Thus, a filter would not lower the heater's PM_{10} emissions by any appreciable amount. Furthermore, research of EPA's RBLC database indicates a filter has not been used to control PM emissions from a comparable heater. These factors indicate it would not be technically feasible to use a filter to control PM emissions from the heater.

Wet Scrubber

The PM_{10}-only profile of the heater's PM emissions indicates a wet scrubber would require a considerable pressure drop to effectively reduce the heater's PM emissions. Additionally, the PM_{10} concentration in the heater's exhaust stream is below the concentration typically seen in a wet scrubber's exhaust stream. Furthermore, the liquid carryover in the exhaust stream from a wet scrubber contains dissolved and suspended solids, which would result in a new PM emission mechanism, reducing any negligible PM_{10} control effectiveness of the wet scrubber in this application. Moreover, research of EPA's RBLC database indicates a wet scrubber has not been used to control PM emissions from a comparable heater. These factors indicate it would not be technically feasible to use a wet scrubber to control PM emissions from the heater.

Cyclone

The PM_{10}-only profile of the heater's PM emissions would limit the control effectiveness of a cyclone. Additionally, the PM_{10} concentration in the heater's exhaust stream is below the concentration typically seen in a cyclone's exhaust stream. Thus, a cyclone would not lower the heater's PM_{10} emissions by any appreciable amount. Furthermore, research of EPA's RBLC database indicates a cyclone has not been used to control PM emissions from a comparable heater. These factors indicate it would not be technically feasible to use a cyclone to control PM emissions from the heater.

Step 3: Rank Remaining Control Technologies

The only remaining available PM, PM_{10}, and $PM_{2.5}$ emission control technology for the RDU Fractionator Feed Heater (H-4102) is good combustion practices.

Step 4: Evaluate Most Effective Control Options

The only remaining available PM, PM_{10}, and $PM_{2.5}$ emission control technology for the RDU Fractionator Feed Heater (H-4102) is good combustion practices.

Step 5: Select BACT

MRL determined that good combustion practices represent the maximum air pollution control capability for the PM, PM_{10}, and $PM_{2.5}$ emissions from the RDU Fractionator Feed Heater (H-4102). Therefore, MRL will continue to control PM, PM_{10}, and $PM_{2.5}$ emissions from the heater by using good combustion practices and continuing to comply with the following emission limitations that were previously determined to reflect the performance of the maximum air pollution control capability for this unit:

PM emissions from the heater shall not exceed 0.00051 lb/MMBtu (HHV), based on a 1-hour average;

PM_{10} emissions from the heater shall not exceed 0.00051 lb/MMBtu (HHV), based on a 1-hour average; and

$PM_{2.5}$ emissions from the heater shall not exceed 0.00042 lb/MMBtu (HHV), based on a 1-hour average.

SO_2

The RDU Fractionator Feed Heater (H-4102) will combust a blend of pipeline quality natural gas and RDU off-gas. The natural gas will contain a negligible amount of H2S. Additionally, the RDU off-gas will be treated to minimize its H_2S content. Therefore, the heater will emit only a small amount of SO_2.

The heater is currently subject to the following NSPS Subpart Ja SO_2 emission standards.

Pursuant to NSPS Subpart Ja, the heater shall not burn any refinery fuel gas that contains H_2S in excess of 162 ppmv on a 3-hour rolling average basis and 60 ppmv on a 365 successive calendar day rolling average basis.

However, the heater will not be an affected facility under NSPS Subpart Ja after the MHC is converted to the RDU.

The heater is also subject to the following DEQ SO_2 emission standard, which will continue to apply to the heater after the proposed change in its operation.

Pursuant to ARM 17.8.322(5), the heater shall not burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 ft^3 of gaseous fuel, calculated as H_2S at standard conditions (or approximately 808 ppmv H_2S).

Step 1: Identify Control Technologies

The following are available SO_2 emission control technologies for the RDU Fractionator Feed Heater (H-4102).

Low Sulfur Fuel

Flue Gas Desulfurization

Below, these technologies are generally described.

Low Sulfur Fuel

A gaseous fuel may inherently contain low levels of sulfur compounds, or it may be treated to remove sulfur compounds using absorption or adsorption technologies. For example, pipeline quality natural gas may be from a well that produces inherently low sulfur gas, or it may be treated

using absorption or adsorption technology to lower its sulfur content. Low sulfur gaseous fuels result in low levels of SO_2 emissions when they are combusted.

Flue Gas Desulfurization

Flue gas desulfurization is commonly used to reduce SO_2 emissions from coal-fired and oil- fired combustion sources due to the relatively high concentration of SO_2 (thousands of ppmv) contained in the flue gas generated by these sources. Flue gas desulfurization can be accomplished using wet, semi-dry, and dry scrubbers, although wet scrubbers are normally capable of higher SO_2 removal efficiencies than semi-dry and dry scrubbers.

In a wet scrubber, an aqueous slurry of sorbent is injected into a source's flue gas and the SO_2 contained in the gas dissolves into the slurry droplets where it reacts with an alkaline compound present in the slurry. The treated flue gas is then emitted to the atmosphere after passing through a mist eliminator that is designed to remove any entrained slurry droplets, while the falling slurry droplets make their way to the bottom of the scrubber where they are collected and either regenerated and recycled or removed as a waste or byproduct.

Semi-dry scrubbers are like wet scrubbers, but the slurry used in a semi-dry scrubber has a higher sorbent concentration, which results in the complete evaporation of the slurry water and the formation of a dry spent sorbent material that is entrained in the treated flue gas. This dry spent sorbent is removed from the flue gas using a baghouse or ESP. In a dry scrubber, a dry sorbent material is pneumatically injected into a source's flue gas and the dry spent sorbent material entrained in the treated flue gas is removed using a baghouse or ESP

Step 2: Eliminate Technically Infeasible Options

Low Sulfur Fuel

Low sulfur fuel is technically feasible for the heater.

Flue Gas Desulfurization

The heater will emit SO_2 at concentrations less than 15 ppmv, which are below the concentrations oftentimes seen in a wet scrubber's exhaust stream. Additionally, the liquid carryover in the exhaust stream from a wet scrubber or the solid carryover in the exhaust stream from a semi-dry or dry scrubber would result in a new PM emission mechanism for the heater. Moreover, research of EPA's RBLC database indicates wet, semi-dry, and dry scrubbers have not been used to control SO_2 emissions from a comparable heater. These factors indicate it would not be technically feasible to use flue gas desulfurization technologies to control SO_2 emissions from the heater.

Step 3: Rank Remaining Control Technologies
The only remaining available SO_2 emission control technology for the RDU Fractionator Feed Heater (H-4102) is low sulfur fuel.

Step 4: Evaluate Most Effective Control Technologies
The only remaining available SO_2 emission control technology for the RDU Fractionator Feed Heater (H-4102) is low sulfur fuel.

Step 5: Select BACT
MRL determined that combusting low sulfur gaseous fuel represents BACT for the SO_2 emissions from the RDU Fractionator Feed Heater (H- 4102). Specifically, MRL will control SO_2 emissions from the RDU Fractionator Feed Heater (H-4102) by combusting gaseous fuel meeting the following H_2S standards: ≤30 ppmv H_2S and ≤10 ppmv H2S on an annual average basis.

VOC

The RDU Fractionator Feed Heater (H-4102) will emit VOC due to the incomplete oxidation of hydrocarbons present in the heater's gaseous fuel. However, the low molecular weight characteristic of the hydrocarbons in the fuel will promote low levels of VOC emissions from the heater.

Furthermore, the heater is equipped with an oxygen monitoring system, which allows the plant to make on-line optimization adjustments to the heater's combustion process, as needed. This system greatly assists in minimizing the heater's VOC emissions by providing the plant with the capability to maintain good combustion practices at the heater.

The heater is not currently subject to an NSPS or NESHAP VOC emission standard, and it will not be subject to an NSPS or NESHAP VOC emission standard after the proposed change in its operation. However, the heater will continue to be subject to the following NESHAP Subpart DDDDD work practice standards that will minimize its VOC emissions.

Pursuant to 40 CFR 63.7540(a)(10)(i), MRL will inspect the heater's burners, and clean or replace any components of the burners as necessary.

Pursuant to 40 CFR 63.7540(a)(10)(ii), MRL will inspect the flame pattern of the heater's burners and adjust the burners as necessary to optimize the flame pattern, consistent with the manufacturer's specifications.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for the RDU Fractionator Feed Heater (H-4102).

Good Combustion Practices

Thermal Oxidation

Catalytic Oxidation

Good Combustion Practices: See page 13 discussion.
Thermal Oxidation See page 13 discussion.
Catalytic Oxidation: See page 13 discussion.

Step 2: Eliminate Technically Infeasible Options

Good Combustion Practices:
Good combustion practices are an integral component of the design and operation of the heater. Therefore, this option is technically feasible for the heater.

Thermal Oxidation
Thermal oxidation is not technically feasible for the control of VOC emissions from the heater due to the very low concentration of VOC in its exhaust stream. The application of thermal oxidation to reduce the heater's VOC emission rate would require the combustion of a considerable amount of fuel to achieve the elevated temperature necessary to promote the oxidation of the small amount of VOC that will be present in the heater's exhaust stream. This fuel combustion would generate additional combustion pollutants, including VOC. Thus, the VOC emission reduction effectiveness of the thermal oxidation system would be reduced, if not negated, because of the VOC generated by the thermal oxidation process.

In summary, the addition of a second thermal oxidation process to the heater system may not reduce the heater's VOC emissions by any appreciable amount, if at all, and this add-on control technology would considerably increase the energy requirements of the heater system while notably increasing the amount of combustion pollutants, such as NOx and CO_2, emitted into the atmosphere. Furthermore, research of EPA's RBLC database indicates thermal oxidation has not been used to control VOC emissions from a comparable heater. These factors indicate it is not technically feasible to use thermal oxidation to control VOC emissions from the heater.

Catalytic Oxidation
Catalytic oxidation is not technically feasible for the control of VOC emissions from the heater because its exhaust gas temperature is too low for the effective operation of the oxidation catalyst. The optimum temperature range for catalytic oxidation is 850 to 1,100°F. Below temperatures of 500 to 600°F, the VOC removal efficiency of the oxidation catalyst is considerably reduced. As previously discussed, the heater's convection section incorporates heat recovery in the form of a feed preheat coil. The exhaust gas temperature after this heat recovery operation is too low for the effective operation of catalytic oxidation. Moreover, due to the considerably low concentration of VOC in the heater's exhaust stream, the potential effectiveness of a catalytic oxidation system would be limited in this case.

Step3: Rank Remaining Control Technologies
The only remaining available VOC emission control technology for the RDU Fractionator Feed Heater (H-4102) is good combustion practices.

Step 4: Evaluate Most Effective Control Options
The only remaining available VOC emission control technology for the RDU Fractionator Feed Heater (H-4102) is good combustion practices.

Step 5: Select BACT
MRL determined that good combustion practices represent the maximum air pollution control capability for the VOC emissions from the RDU Fractionator Feed Heater (H-4102). Therefore, MRL will control VOC emissions from the heater by using good combustion practices.

Hot Oil Heater (H-4201)

CO

The Hot Oil Heater (H-4201) will combust pipeline quality natural gas, which is primarily comprised of low molecular weight hydrocarbons. The heater will emit CO due to the incomplete oxidation of

hydrocarbons present in the natural gas. However, natural gas is a low-carbon fuel. This fuel characteristic will promote low levels of CO emissions from the heater.

Furthermore, the heater will be equipped with an oxygen monitoring system, which will allow the plant to make on-line optimization adjustments to its combustion process, as needed. This system will greatly assist in minimizing the heater's CO emissions by providing the plant with the capability to maintain good combustion practices at the heater.

The heater will not be subject to an NSPS or NESHAP CO emission standard. However, it will be subject to the following NESHAP Subpart DDDDD work practice standards that will minimize its CO emissions.

Pursuant to 40 CFR 63.7540(a)(10)(i), MRL will inspect the heater's burner(s), and clean or replace any components of the burner(s) as necessary.

Pursuant to 40 CFR 63.7540(a)(10)(ii), MRL will inspect the flame pattern of the heater's burner(s) and adjust the burner(s) as necessary to optimize the flame pattern, consistent with the manufacturer's specifications.

Pursuant to 40 CFR 63.7540(a)(10)(iv), MRL will optimize total emissions of CO from the heater. This optimization will be consistent with the manufacturer's specifications and any NOx emission limitation to which the heater is subject

Pursuant to 40 CFR 63.7540(a)(10)(v), MRL will measure the CO and oxygen concentrations in the heater's exhaust stream before and after making the adjustments referenced above.

Step 1: Identify Control Technologies
The following are available CO emission control technologies for the Hot Oil Heater (H- 4201).

Good Combustion Practices

Thermal Oxidation

Catalytic Oxidation

Good Combustion Practices See page 13 discussion.
Thermal Oxidation See page 13 discussion.
Catalytic Oxidation See page 13 discussion.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the CO emission control technologies determined to be available for the Hot Oil Heater (H-4201) is evaluated below.

Good Combustion Practices
Good combustion practices will be an integral component of the design and operation of the heater. Therefore, this option is technically feasible for the heater.

Thermal Oxidation
Thermal oxidation is not technically feasible for the control of CO emissions from the heater due to the very low concentration of CO expected to be present in its exhaust stream. The application of

thermal oxidation to reduce the heater's CO emission rate would require the combustion of a considerable amount of fuel to achieve the elevated temperature necessary to promote the oxidation of the small amount of CO that will be present in the heater's exhaust stream. This fuel combustion would generate additional combustion pollutants, including CO. Thus, the CO emission reduction effectiveness of the thermal oxidation system would be reduced, if not negated, because of the CO generated by the thermal oxidation process.

In summary, the addition of a second thermal oxidation process to the heater system may not reduce the heater's CO emissions by any appreciable amount, if at all, and this add-on control technology would considerably increase the energy requirements of the heater system while notably increasing the amount of combustion pollutants, such as NOx and CO2, emitted into the atmosphere. Furthermore, research of EPA's RBLC database indicates thermal oxidation has not been used to control CO emissions from a comparable heater. Based on these factors, MRL determined that it is not technically feasible to use thermal oxidation to control the heater's CO emissions.

Catalytic Oxidation
Catalytic oxidation is not technically feasible for the control of CO emissions from the heater because its exhaust gas temperature will be too low for the effective operation of the oxidation catalyst. The optimum temperature range for catalytic oxidation is 850 to 1,100°F. Below temperatures of 500 to 600°F, the CO removal efficiency of the oxidation catalyst is considerably reduced. The heater's convection section will incorporate a coil to recover heat to increase the temperature of the hot oil heated in the heater. The exhaust gas temperature after this heat recovery operation will not be optimal for catalytic oxidation. Moreover, due to the considerably low concentration of CO in the heater's exhaust stream, the potential effectiveness of a catalytic oxidation system in this case would be limited.

Step 3: Rank Remaining Control Technologies
The only remaining available CO emission control technology for the Hot Oil Heater (H- 4201) is good combustion practices

Step 4: Evaluate Most Effective Control Technologies
The only remaining available CO emission control technology for the Hot Oil Heater (H- 4201) is good combustion practices.

Step 5: Select BACT
MRL determined that good combustion practices represent the maximum air pollution control capability for CO emissions from the Hot Oil Heater (H-4201). Therefore, MRL will control CO emissions from the heater by using good combustion practices and complying with the following emission limitation: CO emissions from the Hot Oil Heater (H-4201) shall not exceed 0.04 lb/MMBtu (HHV), based on a 1-hour average.

NOx

The Hot Oil Heater (H-4201) will emit NOx, primarily due to the "thermal" and "prompt" NOx generation mechanisms because the heater's pipeline quality natural gas fuel is not expected to contain organo-nitrogen compounds that result in "fuel" NOx emissions. Thermal NOx results from the high temperature thermal dissociation and subsequent reaction of combustion air molecular nitrogen and oxygen, and it tends to be generated in the high temperature zone near the burner of an external combustion device. The rate of thermal NOx generation is affected by the

following three factors: oxygen concentration, peak flame temperature, and duration at peak flame temperature. As these three factors increase in value, the rate of thermal NOx generation increases.

Prompt NOx occurs at the flame front through the relatively fast reaction between combustion air nitrogen and oxygen molecules and fuel hydrocarbon radicals, which are intermediate species formed during the combustion process. Prompt NOx may represent a meaningful portion of the NOx emissions resulting from LNBs and ULNBs due to the relatively low levels of thermal NOx generated by these burners.

The heater will not be subject to an NSPS NOx emission standard.

Step 1: Identify Control Technologies
The following are available NOx emission control technologies for the Hot Oil Heater (H- 4201).

LNBs/ULNBs

SCR

SNCR

NSCR

LNBs/ULNBs See page 13 discussion.
SCR See page 15 discussion.
SNCR See page 16 discussion

NSCR See page 16 discussion.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the NOx emission control technologies determined to be available for the Hot Oil Heater (H-4201) is evaluated below.

LNBs/ULNBs
This option is technically feasible.

SCR
This option is technically feasible.

SNCR
SNCR is not technically feasible for the control of NOx emissions from the heater. A large firebox volume is needed to provide the necessary residence time to achieve the thorough mixing of elevated temperature combustion gas and reagent to successfully reduce NOx emissions using SNCR. However, the heater will have a small firebox volume because it will be designed to minimize space while safely maximizing thermal efficiency.

Additionally, the heater's tube design will be focused on thermal efficiency, providing minimal flexibility to incorporate reagent injection nozzles. This limited flexibility for the placement of reagent injection nozzles is exaggerated when considering accommodations necessary for the heater to operate at varying turndown ratios to be able to stably operate at a wide range of hot oil heating rates. Reagent injection nozzles would likely be required at several locations in the heater's firebox to

accommodate the varying loads. However, the heater's small firebox and tube design will not accommodate this layout.

In sum, it is not technically feasible to use SNCR to control NOx emissions from the heater because the heater's small firebox volume and tube design will not effectively accommodate SNCR operations.

NSCR
NSCR technology is not technically feasible for the control of NOx emissions from the heater because it will not operate at the 0.5% or less excess oxygen concentration necessary to ensure NOx reduction with NSCR. Instead, the heater will be designed to operate with an excess oxygen concentration of approximately 3%. This amount of excess oxygen will promote both low levels of CO and high combustion (thermal) efficiency. Furthermore, research of EPA's RBLC database indicates NSCR has not been used to control NOx emissions from a comparable heater. These factors indicate it is not technically feasible to use NSCR to control the heater's NOx emissions

Step 3: Rank Remaining Control Technologies
The remaining available NOx emission control technologies for the Hot Oil Heater (H-4201) are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions.

SCR

ULNBs: this control technology was incorporated into the emissions unit's baseline emissions because the unit's design basis incorporates ULNBs

Step 4: Evaluate Most Effective Control Options
Below, we evaluate the cost effectiveness of the installation and operation of the NOx emission control technologies that were determined to be technically feasible for the Hot Oil Heater (H-4201) but not already included in its base design.

SCR
MRL estimated that the installation and operation of an SCR system on the heater would result in a cost effectiveness equal to approximately $103,297 per ton of NOx emission reduction, which is not cost effective. The installation of an SCR system on the heater would require additional energy to operate the SCR system's electrical equipment (e.g., pumps, heaters/vaporizers, instrumentation) and provide fan power to overcome the pressure drop across the SCR catalyst bed(s). This increase in electricity usage at the plant would likely result in increased GHG and non-GHG emission rates at one or more power generating stations, reducing the net environmental benefit of the SCR system. Furthermore, the SCR catalyst would require periodic replacement, which would result in a spent catalyst waste stream. This waste stream may represent hazardous waste depending on the composition of the catalyst and the heater's combustion products collected on the catalyst. Lastly, an SCR system would experience ammonia slip during operation, resulting in ammonia emissions from the heater's stack, which may negatively impact regional haze due to an increase in the amount of atmospheric ammonia available to generate visibility impairing ammonium nitrates and ammonium sulfates.

In summary, MRL determined that it would not be cost effective to equip the heater with an SCR system, and the operation of an SCR system on the heater would likely result in collateral emissions of GHG and non-GHG pollutants, as well as the generation of an additional solid waste stream at the site. For these reasons, MRL eliminated an SCR system from consideration as the maximum air pollution control capability for the heater's NOx emissions.

Step 5: Select BACT
MRL determined that ULNBs represent the maximum air pollution control capability for the NOx emissions from the Hot Oil Heater (H-4201). Therefore, MRL will control NOx emissions from the heater by equipping it with ULNBs and complying with the following emission limitation: NOx emissions from the Hot Oil Heater (H-4201) shall not exceed 0.02 lb/MMBtu (HHV), based on a 1-hour average.

PM/PM_{10}/$PM_{2.5}$

The Hot Oil Heater (H-4201) will emit PM_{10} and $PM_{2.5}$ comprised of filterable and condensable portions. A gaseous fuel combustion device can emit PM_{10} and $PM_{2.5}$ at elevated levels due to the incomplete combustion of higher molecular weight hydrocarbons present in the device's gaseous fuel. However, the heater will combust pipeline quality natural gas, which is primarily comprised of low molecular weight hydrocarbons. Therefore, elevated PM_{10} and $PM_{2.5}$ emissions from the heater as a result of the incomplete combustion of high molecular weight hydrocarbons are not expected to occur. Additionally, the natural gas will contain negligible levels of sulfur-containing compounds, further minimizing the generation of PM_{10} and $PM_{2.5}$ when it is combusted.

The heater will not be subject to an NSPS or NESHAP PM, PM_{10}, or $PM_{2.5}$ emission standard. However, it will be subject to the following DEQ opacity and PM standards.

Pursuant to ARM 17.8.304(2), emissions from the heater shall not exceed an opacity of 20% or greater averaged over 6 consecutive minutes.

Pursuant to ARM 17.8.309, PM emissions from the heater shall not exceed 0.44 lb/MMBtu.

Step 1: Identify Control Technologies

Good Combustion Practices

ESP

Filter

Wet Scrubber

Cyclone

Good Combustion Practices See page 13 discussion.
ESP See page 19 discussion
Filter See page 19 discussion
Wet Scrubber See page 20 discussion.
Cyclone See page 20 discussion.

Step 2: Eliminate Technically Infeasible Options

Good Combustion Practices
Good combustion practices will be an integral component of the design and operation of the heater. Therefore, this option is technically feasible for the heater.

ESP
MRL estimated that the PM emitted by the heater will be PM_{10} only, which is a characteristic that would limit the control effectiveness of an ESP. Additionally, the PM_{10} concentration in the heater's exhaust stream will be below the concentration typically seen in an ESP's exhaust stream. Thus, an ESP would not lower the heater's PM_{10} emissions by any appreciable amount. Furthermore, research of EPA's RBLC database indicates an ESP has not been used to control PM emissions from a comparable heater. These factors indicate it would not be technically feasible to use an ESP to control PM emissions from the heater.

Filter
The PM_{10}-only profile of the heater's PM emissions would limit the control effectiveness of a filter. Additionally, the PM_{10} concentration in the heater's exhaust stream will be below the concentration typically seen in a filter's exhaust stream. Thus, a filter would not lower the heater's PM_{10} emissions by any appreciable amount. Furthermore, research of EPA's RBLC database indicates a filter has not been used to control PM emissions from a comparable heater. These factors indicate it would not be technically feasible to use a filter to control PM emissions from the heater.

Wet Scrubber
The PM_{10}-only profile of the heater's PM emissions indicates a wet scrubber would require a considerable pressure drop to effectively reduce the heater's PM emissions. Additionally, the PM_{10} concentration in the heater's exhaust stream will be below the concentration typically seen in a wet scrubber's exhaust stream. Furthermore, the liquid carryover in the exhaust stream from a wet scrubber contains dissolved and suspended solids, which would result in a new PM emission mechanism, reducing any negligible PM_{10} control effectiveness of the wet scrubber in this application. Moreover, research of EPA's RBLC database indicates a wet scrubber has not been used to control PM emissions from a comparable heater. These factors indicate it would not be technically feasible to use a wet scrubber to control PM emissions from the heater.

Cyclone
The PM_{10}-only profile of the heater's PM emissions would limit the control effectiveness of a cyclone. Additionally, the PM_{10} concentration in the heater's exhaust stream will be below the concentration typically seen in a cyclone's exhaust stream. Thus, a cyclone would not lower the heater's PM_{10} emissions by any appreciable amount. Furthermore, research of EPA's RBLC database indicates a cyclone has not been used to control PM emissions from a comparable heater. These factors indicate it would not be technically feasible to use a cyclone to control PM emissions from the heater.

Step 3: Rank Remaining Control Technologies
The only remaining available PM, PM_{10}, and $PM_{2.5}$ emission control technology for the Hot Oil Heater (H-4201) is good combustion practices.

Step 4: Evaluate Most Effective Control Technologies
The only remaining available PM, PM_{10}, and $PM_{2.5}$ emission control technology for the Hot Oil Heater (H-4201) is good combustion practices.

Step 5: Select BACT
MRL determined that good combustion practices represent the maximum air pollution control capability for the PM, PM_{10}, and $PM_{2.5}$ emissions from the Hot Oil Heater (H-4201). Therefore, MRL will control PM, PM_{10}, and $PM_{2.5}$ emissions from the heater by using good combustion practices.

SO_2

The Hot Oil Heater (H-4201) will combust pipeline quality natural gas, which will contain negligible levels of sulfur-containing compounds. Therefore, the heater will emit only a small amount of SO_2 due to natural gas combustion.

The heater will not be subject to an NSPS SO_2 emission standard. However, it will be subject to the following DEQ SO_2 emission standard.

Pursuant to ARM 17.8.322(5), the heater shall not burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 ft^3 of gaseous fuel, calculated as H2S at standard conditions (or approximately 808 ppmv H_2S).

Step 1: Identify Control Technologies
The following are available SO_2 emission control technologies for the Hot Oil Heater (H- 4201).

Low Sulfur Fuel -See page 22

Flue Gas Desulfurization See page 23

Step 2: Eliminate Technically Infeasible Options
Low Sulfur Fuel is technically feasible.

Flue Gas Desulfurization
The heater will emit SO_2 at negligible concentrations, considerably below the concentrations oftentimes seen in a wet scrubber's exhaust stream. Additionally, the liquid carryover in the exhaust stream from a wet scrubber or the solid carryover in the exhaust stream from a semi-dry or dry scrubber would result in a new PM emission mechanism for the heater.

Moreover, research of EPA's RBLC database indicates wet, semi-dry, and dry scrubbers have not been used to control SO_2 emissions from a comparable heater. These factors indicate it would not be technically feasible to use flue gas desulfurization technologies to control SO_2 emissions from the heater

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The only remaining available SO_2 emission control technology for the Hot Oil Heater (H- 4201) is low sulfur fuel.

Step 4: Evaluate Most Effective Control Options
The only remaining available SO_2 emission control technology for the Hot Oil Heater (H- 4201) is low sulfur fuel.

Step 5: Select BACT
MRL determined that combusting low sulfur gaseous fuel represents the maximum air pollution control capability for the SO_2 emissions from the Hot Oil Heater (H-4201).Specifically, MRL will control SO_2 emissions from the Hot Oil Heater (H-4201) by combusting pipeline quality natural gas.

VOC

The Hot Oil Heater (H-4201) will emit VOC due to the incomplete oxidation of hydrocarbons present in the heater's pipeline quality natural gas fuel. However, the low molecular weight characteristic of the hydrocarbons in the natural gas will promote low levels of VOC emissions from the heater.

Furthermore, the heater will be equipped with an oxygen monitoring system, which will allow the plant to make on-line optimization adjustments to the heater's combustion process, as needed. This system will greatly assist in minimizing the heater's VOC emissions by providing the plant with the capability to maintain good combustion practices at the heater.

The heater will not be subject to an NSPS or NESHAP VOC emission standards. However, it will be subject to the following NESHAP Subpart DDDDD work practice standards that will minimize its VOC emissions.

Pursuant to 40 CFR 63.7540(a)(10)(i), MRL will inspect the heater's burner(s), and clean or replace any components of the burner(s) as necessary.

Pursuant to 40 CFR 63.7540(a)(10)(ii), MRL will inspect the flame pattern of the heater's burner(s) and adjust the burner(s) as necessary to optimize the flame pattern, consistent with the manufacturer's specifications.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for the Hot Oil Heater (H- 4201).

Good Combustion Practices

Thermal Oxidation

Catalytic Oxidation

Below, these technologies are generally described.

Good Combustion Practices
Please see page 13 discussion.

Thermal Oxidation
Please see page 13 discussion.

Catalytic Oxidation
Please see page 13 discussion.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the VOC emission control technologies determined to be available for the Hot Oil Heater (H-4201) is evaluated below.

Good Combustion Practices
Good combustion practices will be an integral component of the design and operation of the heater. Therefore, this option is technically feasible for the heater

Thermal Oxidation
Thermal oxidation is not technically feasible for the control of VOC emissions from the heater due to the very low concentration of VOC expected to be present in its exhaust stream. The application of thermal oxidation to reduce the heater's VOC emission rate would require the combustion of a considerable amount of fuel to achieve the elevated temperature necessary to promote the oxidation of the small amount of VOC that will be present in the heater's exhaust stream. This fuel combustion would generate additional combustion pollutants, including VOC. Thus, the VOC emission reduction effectiveness of the thermal oxidation system would be reduced, if not negated, because of the VOC generated by the thermal oxidation process.

In summary, the addition of a second thermal oxidation process to the heater system may not reduce the heater's VOC emissions by any appreciable amount, if at all, and this add-on control technology would considerably increase the energy requirements of the heater system while notably increasing the amount of combustion pollutants, such as NOx and CO2, emitted into the atmosphere. Furthermore, research of EPA's RBLC database indicates thermal oxidation has not been used to control VOC emissions from a comparable heater. These factors indicate it is not technically feasible to use thermal oxidation to control VOC emissions from the heater.

Catalytic Oxidation
Catalytic oxidation is not technically feasible for the control of VOC emissions from the heater because its exhaust gas temperature will be too low for the effective operation of the oxidation catalyst. The optimum temperature range for catalytic oxidation is 850 to 1,100°F. Below temperatures of 500 to 600°F, the VOC removal efficiency of the oxidation catalyst is considerably reduced. As previously discussed, the heater's convection section will incorporate heat recovery to heat hot oil. The exhaust gas temperature after this heat recovery operation will not be optimal for catalytic oxidation. Moreover, due to the considerably low concentration of VOC in the heater's exhaust stream, the potential effectiveness of a catalytic oxidation system would be limited in this case.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The only remaining available VOC emission control technology for the Hot Oil Heater (H- 4201) is good combustion practices.

Step 4: Evaluate Most Effective Control Options
The only remaining available VOC emission control technology for the Hot Oil Heater (H- 4201) is good combustion practices.

Step 5: Select BACT
MRL determined that good combustion practices represent the maximum air pollution control capability for the VOC emissions from the Hot Oil Heater (H-4201). Therefore, MRL will control VOC emissions from the heater by using good combustion practices

Tank #306

VOC

Tank #306 will be an atmospheric fixed roof storage tank storing a VOC-containing material. The emissions mechanisms for the storage tank will be the following two mechanisms: (1) the contraction and expansion of the vapor in the vapor space of the tank caused by operating temperature fluctuations; and (2) the hydraulic displacement of vapor caused by cyclic increases in the tank's liquid level. The first mechanism results in breathing emissions, while the second mechanism results in working emissions.

The storage tank will not be subject to an NSPS or NESHAP VOC emission standard.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for Tank #306.

Internal Floating Roof (IFR) Storage Tank with Vapor Collection System and Control Device

Fixed Roof Storage Tank with Vapor Collection System and Control Device

IFR Storage Tank

EFR Storage Tank

Fixed Roof Storage Tank with Submerged Fill Below, these technologies are generally described.

IFR Storage Tank with Vapor Collection System and Control Device
An IFR storage tank is equipped with two roofs – a fixed roof connected to the top of the storage tank wall and a floating roof (the IFR) that rests on the surface of the liquid contained in the storage tank. In general, a floating roof design effectively eliminates the breathing and working emissions that result from a fixed roof storage tank because the floating roof eliminates the vapor space that would be present in a fixed roof tank by directly contacting nearly all of the liquid surface area. Additionally, certain emissions mechanisms and floating roof operating and maintenance risks that exist for an EFR tank (a tank where the floating roof is exposed to the atmosphere) do not exist for an IFR tank because the IFR tank's floating roof is not directly exposed to the atmosphere since the tank's fixed roof is located above the floating roof.

Because an IFR tank incorporates a fixed roof above a floating roof, the vapor between the floating roof and fixed roof can be collected and routed to a control device to reduce VOC emissions to the atmosphere. The following are examples of the types of control devices that can be used to reduce VOC emissions from the vapor collected from an IFR tank:

Condenser;

Thermal oxidizer; and

Carbon adsorption.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
A fixed roof storage tank contains a vapor space between the surface of the liquid contained in the tank and the roof of the tank, and this vapor space is partially comprised of the compounds making up the liquid contained in the tank. A portion of the vapor contained in the vapor space of an atmospheric fixed roof storage tank is routinely vented to the atmosphere because of the breathing and working emissions mechanisms described above.

A fixed roof tank can be equipped with a vapor collection system to collect the vapor vented from the tank. This collected vapor can then be routed to a control device to reduce VOC emissions to the atmosphere. The following are examples of the types of control devices that can be used to reduce VOC emissions from the vapor collected from a fixed roof tank:

Condenser;

Thermal oxidizer; and

Carbon adsorption.

IFR Storage Tank
As described above, an IFR storage tank is equipped with two roof structures – a fixed roof located above a floating roof (the IFR). In general, a floating roof design effectively eliminates the breathing and working emissions that result from a fixed roof storage tank because the floating roof eliminates the vapor space that would be present in a fixed roof tank by directly contacting nearly all of the liquid surface area. Additionally, certain emissions mechanisms and floating roof operating and maintenance risks that exist for an EFR tank do not exist for an IFR tank because the IFR tank's floating roof is not directly exposed to the atmosphere since the tank's fixed roof is located above its floating roof. As a result, emissions from an IFR tank are typically lower than the emissions that would occur from an otherwise identical EFR tank containing the same material at the same storage conditions.

EFR Storage Tank
An EFR storage tank is equipped with a roof structure that rests on the surface of the liquid contained in the storage tank, and this floating roof is exposed to the atmosphere. As discussed above for an IFR tank, a floating roof design effectively eliminates the breathing and working emissions that result from a fixed roof storage tank. However, emissions from an EFR tank tend to be higher than from an IFR tank because the rim seal and openings of an EFR tank are directly exposed to the atmosphere and, therefore, the emissions from these seals and openings are influenced by wind conditions.

Fixed Roof Storage Tank with Submerged Fill
There are two mechanisms that result in emissions from a fixed roof storage tank. The first mechanism results in breathing emissions, while the second mechanism results in working emissions. By incorporating submerged fill into the design of a fixed roof storage tank, the saturation level of the vapor space between the surface of the liquid contained in the tank and the roof of the tank can be reduced versus the level that would occur if the liquid were introduced into the tank under splash loading conditions. Therefore, by reducing the saturation level of the vapor space, the vapor vented from the storage tank contains less VOC, which means lower VOC emissions to the atmosphere.

Step 2: Eliminate Technically Infeasible Options
IFR Storage Tank with Vapor Collection System and Control Device
This option is technically feasible for the tank.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
This option is technically feasible for the tank.

IFR Storage Tank
This option is technically feasible for the tank.

EFR Storage Tank
This option is technically feasible for the tank.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill will be an integral component of the base design and operation of the tank. Therefore, this option is technically feasible for the tank.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The remaining available VOC emission control technologies for the tank are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions.

IFR Storage Tank with Vapor Collection System and Control Device

Fixed Roof Storage Tank with Vapor Collection System and Control Device

IFR Storage Tank

EFR Storage Tank

Fixed Roof Storage Tank with Submerged Fill: this control technology was incorporated into the emissions unit's baseline emissions because the unit's design basis incorporates a fixed roof and submerged fill.

Step 4: Evaluate Most Effective Control Options
Below, we evaluate the cost effectiveness of the installation and operation of the VOC emission control technologies that were determined to be technically feasible for the tank but not already included in its base design.

IFR Storage Tank with Vapor Collection System and Control Device
MRL estimated that the installation and operation of an IFR storage tank would be more costly than a fixed roof tank. Also, the plant would be required to expend at least $1,250,000 to install piping, associated equipment (e.g., valves and instrumentation), and a thermal oxidizer to collect and control the IFR tank's VOC emissions. Furthermore, annual operating costs (e.g., fuel, electricity, maintenance labor, and maintenance materials) required to operate and maintain the thermal oxidizer would make it even less cost-effective. In consideration of the minor 0.87 tpy VOC emission rate calculated for a fixed roof version of the tank and the higher costs to install and operate an IFR storage tank and vapor collection and control system on the IFR tank, MRL concluded that it would not be cost effective to install an IFR storage tank equipped with a vapor collection and control system. Therefore, MRL eliminated an IFR storage tank with a vapor

collection system and control device from consideration as the maximum air pollution control capability for the tank's VOC emissions.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
MRL estimated that the installation of piping, associated equipment (e.g., valves and instrumentation), and a thermal oxidizer to collect and control the tank's VOC emissions would cost at least $1,250,000, which is not cost effective in consideration of the minor 0.87 tpy VOC emission rate calculated for a fixed roof version of the tank without any vapor collection system and control device. Additionally, annual operating costs (e.g., fuel, electricity, maintenance labor, and maintenance materials) required to operate and maintain the thermal oxidizer would make it even less cost-effective. Therefore, MRL eliminated a vapor collection system and control device from consideration as the maximum air pollution control capability for the tank's VOC emissions.

The tank's VOC emissions cannot be safely routed to the adjacent CMR Great Falls Refinery's flare system because that flare system's pressure is too high. Therefore, a new combustion control device, such as a thermal oxidizer, would be required to be installed to safely treat the tank's VOC emissions.

IFR Storage Tank
MRL estimated that the installation and operation of an IFR storage tank would be more costly than a fixed roof tank. In consideration of the minor 0.87 tpy VOC emission rate calculated for a fixed roof version of the tank and the higher costs to install and operate an IFR storage tank, MRL concluded that it would not be cost effective to install an IFR storage tank. Therefore, MRL eliminated an IFR storage tank from consideration as the maximum air pollution control capability for the tank's VOC emissions.

EFR Storage Tank
MRL estimated that the installation and operation of an EFR storage tank would be more costly than a fixed roof tank. In consideration of the minor 0.87 tpy VOC emission rate calculated for a fixed roof version of the tank and the higher costs to install and operate an EFR storage tank, MRL concluded that it would not be cost effective to install an EFR storage tank. Therefore, MRL eliminated an EFR storage tank from consideration as the maximum air pollution control capability for the tank's VOC emissions.

Step 5: Select BACT
MRL determined that a fixed roof with submerged fill represents the maximum air pollution control capability for the VOC emissions from Tank #306. Therefore, MRL will control VOC emissions from the tank by equipping it with a fixed roof and submerged fill design.

Tank #307

VOC

Tank #307 will be an atmospheric fixed roof storage tank storing a VOC-containing material. The emissions mechanisms for the storage tank will be the following two mechanisms: (1) the contraction and expansion of the vapor in the vapor space of the tank caused by operating temperature fluctuations; and (2) the hydraulic displacement of vapor caused by cyclic increases in the tank's liquid level. The first mechanism results in breathing emissions, while the second mechanism results in working emissions.

The storage tank will not be subject to an NSPS or NESHAP VOC emission standard.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for Tank #307.

IFR Storage Tank with Vapor Collection System and Control Device

Fixed Roof Storage Tank with Vapor Collection System and Control Device

IFR Storage Tank

EFR Storage Tank

Fixed Roof Storage Tank with Submerged Fill Below, these technologies are generally described.

IFR Storage Tank with Vapor Collection System and Control Device Please see page 35 for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device Please see page 35 herein for a discussion of this technology.

IFR Storage Tank
Please see page 36 for a discussion of this technology.

EFR Storage Tank
Please see page 36 for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see page 36 for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options
Below, we evaluate the technical feasibility of the VOC emission control technologies determined to be available for Tank #307.

IFR Storage Tank with Vapor Collection System and Control Device
This option is technically feasible for the tank.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
This option is technically feasible for the tank.

IFR Storage Tank
This option is technically feasible for the tank.

EFR Storage Tank
This option is technically feasible for the tank.

Fixed Roof Storage Tank with Submerged Fill

Fixed roof with submerged fill will be an integral component of the base design and operation of the tank. Therefore, this option is technically feasible for the tank.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The remaining available VOC emission control technologies for the tank are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions.

IFR Storage Tank with Vapor Collection System and Control Device

Fixed Roof Storage Tank with Vapor Collection System and Control Device

IFR Storage Tank

EFR Storage Tank

Fixed Roof Storage Tank with Submerged Fill: this control technology was incorporated into the emissions unit's baseline emissions because the unit's design basis incorporates a fixed roof and submerged fill.

Step 4: Evaluate Most Effective Control Options
Below, we evaluate the cost effectiveness of the installation and operation of the VOC emission control technologies that were determined to be technically feasible for the tank but not already included in its base design.

IFR Storage Tank with Vapor Collection System and Control Device
MRL estimated that the installation and operation of an IFR storage tank would be more costly than a fixed roof tank. Also, the plant would be required to expend at least $1,250,000 to install piping, associated equipment (e.g., valves and instrumentation), and a thermal oxidizer to collect and control the IFR tank's VOC emissions.53, 54 Furthermore, annual operating costs (e.g., fuel, electricity, maintenance labor, and maintenance materials) required to operate and maintain the thermal oxidizer would make it even less cost-effective. In consideration of the minor 0.87 tpy VOC emission rate calculated for a fixed roof version of the tank and the higher costs to install and operate an IFR storage tank and vapor collection and control system on the IFR tank, MRL concluded that it would not be cost effective to install an IFR storage tank equipped with a vapor collection and control system. Therefore, MRL eliminated an IFR storage tank with a vapor collection system and control device from consideration as the maximum air pollution control capability for the tank's VOC emissions.

The tank's VOC emissions cannot be safely routed to the adjacent CMR Great Falls Refinery's flare system because that flare system's pressure is too high. Therefore, a new combustion control device, such as a thermal oxidizer, would be required to be installed to safely treat the tank's VOC emissions.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
MRL estimated that the installation of piping, associated equipment (e.g., valves and instrumentation), and a thermal oxidizer to collect and control the tank's VOC emissions would cost at least $1,250,000, which is not cost effective in consideration of the minor 0.87 tpy VOC emission rate calculated for a fixed roof version of the tank without any vapor collection system and control device. Additionally, annual operating costs (e.g., fuel, electricity, maintenance labor, and maintenance materials) required to operate and maintain the thermal oxidizer would make it even less cost-effective. Therefore, MRL eliminated a vapor collection system and control device from consideration as the maximum air pollution control capability for the tank's VOC emissions.

IFR Storage Tank
MRL estimated that the installation and operation of an IFR storage tank would be more costly than a fixed roof tank. In consideration of the minor 0.87 tpy VOC emission rate calculated for a fixed roof version of the tank and the higher costs to install and operate an IFR storage tank, MRL concluded that it would not be cost effective to install an IFR storage tank. Therefore, MRL eliminated an IFR storage tank from consideration as the maximum air pollution control capability for the tank's VOC emissions.

EFR Storage Tank
MRL estimated that the installation and operation of an EFR storage tank would be more costly than a fixed roof tank. In consideration of the minor 0.87 tpy VOC emission rate calculated for a fixed roof version of the tank and the higher costs to install and operate an EFR storage tank, MRL concluded that it would not be cost effective to install an EFR storage tank. Therefore, MRL eliminated an EFR storage tank from consideration as the maximum air pollution control capability for the tank's VOC emissions.

Step 5: Select BACT
MRL determined that a fixed roof with submerged fill represents the maximum air pollution control capability for the VOC emissions from Tank #307. Therefore, MRL will control VOC emissions from the tank by equipping it with a fixed roof and submerged fill design.

Tank #308

VOC

Tank #308 will be an atmospheric fixed roof storage tank storing a VOC-containing material. The emissions mechanisms for the storage tank will be the following two mechanisms: (1) the contraction and expansion of the vapor in the vapor space of the tank caused by operating temperature fluctuations; and (2) the hydraulic displacement of vapor caused by cyclic increases in the tank's liquid level. The first mechanism results in breathing emissions, while the second mechanism results in working emissions.

The storage tank will not be subject to an NSPS or NESHAP VOC emission standard.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for Tank #308.

IFR Storage Tank with Vapor Collection System and Control Device

Fixed Roof Storage Tank with Vapor Collection System and Control Device

IFR Storage Tank

EFR Storage Tank

Fixed Roof Storage Tank with Submerged Fill Below, these technologies are generally described.
IFR Storage Tank with Vapor Collection System and Control Device Please see page 35 for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device.
IFR Storage Tank
Please see page 36 for a discussion of this technology.

EFR Storage Tank
Please see page 36 herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see page 36 for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options
Below, we evaluate the technical feasibility of the VOC emission control technologies determined to be available for Tank #308.

IFR Storage Tank with Vapor Collection System and Control Device
This option is technically feasible for the tank.

Fixed Roof Storage Tank with Vapor Collection System and Control Device This option is technically feasible for the tank.

IFR Storage Tank
This option is technically feasible for the tank.

EFR Storage Tank
This option is technically feasible for the tank.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill will be an integral component of the base design and operation of the tank. Therefore, this option is technically feasible for the tank.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The remaining available VOC emission control technologies for the tank are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions.

IFR Storage Tank with Vapor Collection System and Control Device

Fixed Roof Storage Tank with Vapor Collection System and Control Device

IFR Storage Tank

EFR Storage Tank

Fixed Roof Storage Tank with Submerged Fill: this control technology was incorporated into the emissions unit's baseline emissions because the unit's design basis incorporates a fixed roof and submerged fill.

Step 4: Evaluate Most Effective Control Options
Below, we evaluate the cost effectiveness of the installation and operation of the VOC emission control technologies that were determined to be technically feasible for the tank but not already included in its base design.

IFR Storage Tank with Vapor Collection System and Control Device
MRL estimated that the installation and operation of an IFR storage tank would be more costly than a fixed roof tank. Also, the plant would be required to expend at least$1,250,000 to install piping, associated equipment (e.g., valves and instrumentation), and a thermal oxidizer to collect and control the IFR tank's VOC emissions.55, 56 Furthermore, annual operating costs (e.g., fuel, electricity, maintenance labor, and maintenance materials) required to operate and maintain the thermal oxidizer would make it even less cost-effective. In consideration of the minor 1.75 tpy VOC emission rate calculated for a fixed roof version of the tank and the higher costs to install and operate an IFR storage tank and vapor collection and control system on the IFR tank, MRL concluded that it would not be cost effective to install an IFR storage tank equipped with a vapor collection and control system. Therefore, MRL eliminated an IFR storage tank with a vapor collection system and control device from consideration as the maximum air pollution control capability for the tank's VOC emissions.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
MRL estimated that the installation of piping, associated equipment (e.g., valves and instrumentation), and a thermal oxidizer to collect and control the tank's VOC emissions would cost at least $1,250,000, which is not cost effective in consideration of the minor 1.75 tpy VOC emission rate calculated for a fixed roof version of the tank without any vapor collection system and control device. Additionally, annual operating costs (e.g., fuel, electricity, maintenance labor, and maintenance materials) required to operate and maintain the thermal oxidizer would make it even less cost-effective. Therefore, MRL eliminated a vapor collection system and control device from consideration as the maximum air pollution control capability for the tank's VOC emissions.

IFR Storage Tank
MRL estimated that the installation and operation of an IFR storage tank would be more costly than a fixed roof tank. In consideration of the minor 1.75 tpy VOC emission rate calculated for a fixed roof version of the tank and the higher costs to install and operate an IFR storage tank, MRL concluded that it would not be cost effective to install an IFR storage tank. Therefore, MRL eliminated an IFR storage tank from consideration as the maximum air pollution control capability for the tank's VOC emissions.

EFR Storage Tank
MRL estimated that the installation and operation of an EFR storage tank would be more costly than a fixed roof tank. In consideration of the minor 1.75 tpy VOC emission rate calculated for a fixed roof version of the tank and the higher costs to install and operate an EFR storage tank, MRL concluded that it would not be cost effective to install an EFR storage tank. Therefore, MRL eliminated an EFR storage tank from consideration as the maximum air pollution control capability for the tank's VOC emissions.

Step 5: Select BACT
MRL determined that a fixed roof with submerged fill represents the maximum air pollution control capability for the VOC emissions from Tank #308. Therefore, MRL will control VOC emissions from the tank by equipping it with a fixed roof and submerged fill design.

Tank #309

VOC

Tank #309 will be an atmospheric fixed roof storage tank storing a VOC-containing material. The emissions mechanisms for the storage tank will be the following two mechanisms: (1) the contraction and expansion of the vapor in the vapor space of the tank caused by operating temperature fluctuations; and (2) the hydraulic displacement of vapor caused by cyclic increases in the tank's liquid level. The first mechanism results in breathing emissions, while the second mechanism results in working emissions.

The storage tank will not be subject to an NSPS or NESHAP VOC emission standard.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for Tank #309.

IFR Storage Tank with Vapor Collection System and Control Device

Fixed Roof Storage Tank with Vapor Collection System and Control Device

IFR Storage Tank

EFR Storage Tank

Fixed Roof Storage Tank with Submerged Fill Below, these technologies are generally described.
IFR Storage Tank with Vapor Collection System and Control Device Please see page 35 for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device

IFR Storage Tank
Please see page 36 for a discussion of this technology.

EFR Storage Tank
Please see page 36 for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see page 36 for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options
Below, we evaluate the technical feasibility of the VOC emission control technologies determined to be available for Tank #309.

IFR Storage Tank with Vapor Collection System and Control Device This option is technically feasible for the tank.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
This option is technically feasible for the tank.

IFR Storage Tank
This option is technically feasible for the tank.

EFR Storage Tank
This option is technically feasible for the tank.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill will be an integral component of the base design and operation of the tank. Therefore, this option is technically feasible for the tank.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The remaining available VOC emission control technologies for the tank are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions.

IFR Storage Tank with Vapor Collection System and Control Device

Fixed Roof Storage Tank with Vapor Collection System and Control Device

IFR Storage Tank

EFR Storage Tank

Fixed Roof Storage Tank with Submerged Fill: this control technology was incorporated into the emissions unit's baseline emissions because the unit's design basis incorporates a fixed roof and submerged fill.

Step 4: Evaluate Most Effective Control Options
Below, we evaluate the cost effectiveness of the installation and operation of the VOC emission control technologies that were determined to be technically feasible for the tank but not already included in its base design.

IFR Storage Tank with Vapor Collection System and Control Device
MRL estimated that the installation and operation of an IFR storage tank would be more costly than a fixed roof tank. Also, the plant would be required to expend at least $1,250,000 to install piping, associated equipment (e.g., valves and instrumentation), and a thermal oxidizer to collect and control the IFR tank's VOC emissions. Furthermore, annual operating costs (e.g., fuel, electricity, maintenance labor, and maintenance materials) required to operate and maintain the thermal oxidizer would make it even less cost-effective. In consideration of the minor 1.75 tpy VOC emission rate calculated for a fixed roof version of the tank and the higher costs to install and operate an IFR storage tank and vapor collection and control system on the IFR tank, MRL concluded that it would not be cost effective to install an IFR storage tank equipped with a vapor collection and control system. Therefore, MRL eliminated an IFR storage tank with a vapor collection system and control device from consideration as the maximum air pollution control capability for the tank's VOC emissions.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
MRL estimated that the installation of piping, associated equipment (e.g., valves and instrumentation), and a thermal oxidizer to collect and control the tank's VOC emissions would cost at least $1,250,000, which is not cost effective in consideration of the minor 1.75 tpy VOC emission rate calculated for a fixed roof version of the tank without any vapor collection system and control

device. Additionally, annual operating costs (e.g., fuel, electricity, maintenance labor, and maintenance materials) required to operate and maintain the thermal oxidizer would make it even less cost-effective. Therefore, MRL eliminated a vapor collection system and control device from consideration as the maximum air pollution control capability for the tank's VOC emissions.

IFR Storage Tank
MRL estimated that the installation and operation of an IFR storage tank would be more costly than a fixed roof tank. In consideration of the minor 1.75 tpy VOC emission rate calculated for a fixed roof version of the tank and the higher costs to install and operate an IFR storage tank, MRL concluded that it would not be cost effective to install an IFR storage tank. Therefore, MRL eliminated an IFR storage tank from consideration as the maximum air pollution control capability for the tank's VOC emissions.

EFR Storage Tank
MRL estimated that the installation and operation of an EFR storage tank would be more costly than a fixed roof tank. In consideration of the minor 1.75 tpy VOC emission rate calculated for a fixed roof version of the tank and the higher costs to install and operate an EFR storage tank, MRL concluded that it would not be cost effective to install an EFR storage tank. Therefore, MRL eliminated an EFR storage tank from consideration as the maximum air pollution control capability for the tank's VOC emissions.

Step 5: Select BACT
MRL determined that a fixed roof with submerged fill represents the maximum air pollution control capability for the VOC emissions from Tank #309. Therefore, MRL will control VOC emissions from the tank by equipping it with a fixed roof and submerged fill design.

Tank #0801

VOC

Tank #0801 will be an atmospheric fixed roof storage tank storing a VOC-containing material. The emissions mechanisms for the storage tank will be the following two mechanisms: (1) the contraction and expansion of the vapor in the vapor space of the tank caused by operating temperature fluctuations; and (2) the hydraulic displacement of vapor caused by cyclic increases in the tank's liquid level. The first mechanism results in breathing emissions, while the second mechanism results in working emissions.

The storage tank will not be subject to an NSPS or NESHAP VOC emission standard.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for Tank #0801.

IFR Storage Tank with Vapor Collection System and Control Device

Fixed Roof Storage Tank with Vapor Collection System and Control Device

IFR Storage Tank

EFR Storage Tank

Fixed Roof Storage Tank with Submerged Fill Below, these technologies are generally described. IFR Storage Tank with Vapor Collection System and Control Device Please see page 35 for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device Please see page 35 for a discussion of this technology.

IFR Storage Tank
Please see page 36 for a discussion of this technology.

EFR Storage Tank
Please see page 36 for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see page 36 for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options
Below, we evaluate the technical feasibility of the VOC emission control technologies determined to be available for Tank #0801.

IFR Storage Tank with Vapor Collection System and Control Device This option is technically feasible for the tank.

Fixed Roof Storage Tank with Vapor Collection System and Control Device This option is technically feasible for the tank.

IFR Storage Tank
This option is technically feasible for the tank.

EFR Storage Tank
This option is technically feasible for the tank.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill will be an integral component of the base design and operation of the tank. Therefore, this option is technically feasible for the tank.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The remaining available VOC emission control technologies for the tank are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions.

IFR Storage Tank with Vapor Collection System and Control Device

Fixed Roof Storage Tank with Vapor Collection System and Control Device

IFR Storage Tank

EFR Storage Tank

Fixed Roof Storage Tank with Submerged Fill: this control technology was incorporated into the emissions unit's baseline emissions because the unit's design basis incorporates a fixed roof and submerged fill.

Step 4: Evaluate Most Effective Control Options
Below, we evaluate the cost effectiveness of the installation and operation of the VOC emission control technologies that were determined to be technically feasible for the tank but not already included in its base design.

IFR Storage Tank with Vapor Collection System and Control Device
In consideration of the negligible 0.02 tpy VOC emission rate calculated for a fixed roof version of the tank, MRL concluded that it would not be cost effective to install and operate an IFR storage tank equipped with a vapor collection and control system. Therefore, MRL eliminated an IFR storage tank with a vapor collection system and control device from consideration as the maximum air pollution control capability for the tank's VOC emissions.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
In consideration of the negligible 0.02 tpy VOC emission rate calculated for a fixed roof version of the tank without any vapor collection system and control device, MRL concluded that it would not be cost effective to install and operate a vapor collection and control system on the tank. Therefore, MRL eliminated a vapor collection system and control device from consideration as the maximum air pollution control capability for the tank's VOC emissions.

IFR Storage Tank
In consideration of the negligible 0.02 tpy VOC emission rate calculated for a fixed roof version of the tank, MRL concluded that it would not be cost effective to install and operate an IFR version of the storage tank. Therefore, MRL eliminated an IFR storage tank from consideration as the maximum air pollution control capability for the tank's VOC emissions.

EFR Storage Tank
In consideration of the negligible 0.02 tpy VOC emission rate calculated for a fixed roof version of the tank, MRL concluded that it would not be cost effective to install and operate an EFR version of the storage tank. Therefore, MRL eliminated an EFR storage tank from consideration as the maximum air pollution control capability for the tank's VOC emissions.

Step 5: Select BACT
MRL determined that a fixed roof with submerged fill represents the maximum air pollution control capability for the VOC emissions from Tank #0801. Therefore, MRL will control VOC emissions from the tank by equipping it with a fixed roof and submerged fill design.

Tank #4201

VOC

Tank #4201 will be an atmospheric fixed roof storage tank storing a VOC-containing material. The emissions mechanisms for the storage tank will be the following two mechanisms: (1) the contraction and expansion of the vapor in the vapor space of the tank caused by operating temperature fluctuations; and (2) the hydraulic displacement of vapor caused by cyclic increases in the tank's liquid level. The first mechanism results in breathing emissions, while the second mechanism results in working emissions.

Tank #4201 will not be subject to an NSPS or NESHAP VOC emission standard.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for Tank #4201.

Fixed Roof Storage Tank with Vapor Collection System and Control Device

Fixed Roof Storage Tank with Submerged Fill Below, these technologies are generally described.
A floating roof is generally not an available technology for Tank #4201 because of the waxy or fatty physical characteristic of the organic material that will be contained in the PTU wastewater. This characteristic would negatively impact the operability of a floating roof, including the effectiveness of the roof's seals.

Fixed Roof Storage Tank with Vapor Collection System and Control Device Please see page 35 for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see page 36 for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options
Below, we evaluate the technical feasibility of the VOC emission control technologies determined to be available for Tank #4201.

Fixed Roof Storage Tank with Vapor Collection System and Control Device This option is technically feasible for the tank.

Fixed Roof Storage Tank with Submerged Fill This option is technically feasible for the tank.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The remaining available VOC emission control technologies for the tank are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions.

Fixed Roof Storage Tank with Vapor Collection System and Control Device: this control technology was incorporated into the emissions unit's baseline emissions because the unit will be equipped with a fixed roof with vapor collection system and control device.

Fixed Roof Storage Tank with Submerged Fill

Step 4: Evaluate Most Effective Control Options
MRL will install and operate the most effective control technology on Tank #4201. Therefore, it is not necessary to analyze control technology options for the tank.

Step 5: Select BACT
MRL determined that a fixed roof with a carbon adsorption control device represents the maximum air pollution control capability for the VOC emissions from Tank #4201.Therefore, MRL will control VOC emissions from the tank by equipping it with a fixed roof and a carbon adsorption control device.

Hot Oil Expansion Tank (D-4203)

VOC

The Hot Oil Expansion Tank (D-4203) will have the potential to emit VOC to the atmosphere, but it is expected to infrequently vent to the atmosphere for the following reasons:

The vessel will be a pressurized vessel equipped with a pressure regulating valve and the setpoint of this valve will limit the amount of venting from the vessel;

The hot oil level in the vessel is expected to stay relatively constant during routine operations because the vessel will be part of a recirculation circuit in which the recirculating hot oil will typically bypass the vessel; and

The hot oil temperature in the vessel is expected to stay relatively constant during routine operations, again because the vessel will be part of a recirculation circuit in which the recirculating hot oil will typically bypass the vessel.

The process vessel will not be subject to an NSPS or NESHAP VOC emission standard.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for the Hot Oil Expansion Tank (D-4203).

Thermal Oxidation

Catalytic Oxidation

Absorption

Carbon Adsorption

Condensation

Proper Equipment Design and Operating Practices Below, the available technologies are generally described.
Thermal Oxidation

Please see page 13 for a discussion of this technology.

Catalytic Oxidation
Please see page 13 for a discussion of this technology.

Absorption
Absorption is primarily a physical process, though it can also include a chemical component, in which a pollutant in a gas phase contacts a scrubbing media and is removed from the gas phase by the scrubbing media. The common absorption device used to remove VOC from a gaseous stream is a wet scrubber. The wet scrubber provides an intimate contacting environment for the soluble VOC to be dissolved in the scrubbing liquid. Water can be used as the scrubbing liquid in a wet scrubber used for VOC emission control, but very low vapor pressure organic materials are also

used when the VOC requiring control is not soluble in water. In general, VOC containing nitrogen or oxygen atoms that are free to form strong hydrogen bonds and that have one to three carbon atoms are soluble in water. As the number of carbon atoms increases, the VOC is typically less soluble in water to a point where it is insoluble in water. There are several types of wet scrubbers, including packed- bed counterflow scrubbers, packed-bed cross-flow scrubbers, bubble plate scrubbers, and tray scrubbers.

Carbon Adsorption
Carbon adsorption is used to capture a specific compound, or a range of compounds, present in a gas phase on the surface of granular activated carbon. Carbon adsorption performance depends on the type of activated carbon used, the characteristics of the target compound(s), the concentration of the target compound(s) in the gaseous stream, and the temperature, pressure, and moisture content of the gaseous stream. Carbon adsorbers can be of the fixed-bed or fluidized bed design. A fixed-bed carbon adsorber must be periodically regenerated to desorb the collected compounds from the carbon, while a fluidized-bed carbon adsorber is continuously regenerated. Additionally, portable, easily replaceable carbon adsorption units (e.g., 55-gallon drums) are used in some applications. This type of unit is not regenerated at the facility where it is used. Instead, the portable unit is typically returned to the supplier of the unit, and the supplier regenerates or disposes of the spent carbon.

Condensation
In principle, a condenser achieves condensation by lowering the temperature of the gas stream containing a condensable to a temperature at which the desired condensate's vapor pressure is lower than its entering partial pressure. Condensation is performed by a condenser that is either a surface noncontact condenser or a direct-contact condenser. A surface condenser is usually a shell-and-tube heat exchanger in which the cooling fluid flows inside the tubes of the exchanger and the gas undergoing condensation treatment flows on the outside of the tubes. A direct-contact condenser is a device in which intimate contact occurs between the cooling fluid and the gas undergoing condensation treatment, usually in a spray or packed tower. Although a direct-contact condenser may also be part of a chemical recovery system, an extra separation step is usually required to separate the cooling liquid from the newly formed condensate. Examples of cooling fluids used in condensers are water, brine cooled to below the freezing point of pure water, and refrigerants.

Proper Equipment Design and Operating Practices
As discussed above, the process vessel will be designed and operated to minimize venting episodes. Therefore, the amount of VOC emissions from the vessel will be low.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the VOC emission control technologies determined to be available for the Hot Oil Expansion Tank (D-4203) is evaluated below.

Thermal Oxidation
This option is technically feasible for the process vessel.

Catalytic Oxidation
This option is technically feasible for the process vessel.

Absorption
This option is technically feasible for the process vessel.

Carbon Adsorption

This option is technically feasible for the process vessel.

Condensation
This option is technically feasible for the process vessel.

Proper Equipment Design and Operating Practices This option is technically feasible for the process vessel.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The available add-on VOC emission control technologies for the Hot Oil Expansion Tank (D-4203) are all effectively the same with respect to VOC emission control capabilities. The different technologies do however have varying energy requirements (e.g., electricity and fuel) and generate unique waste products (e.g., wastewater, solid waste, or combustion emissions).

Step 4: Evaluate Most Effective Control Options
As noted above, the available add-on VOC emission control technologies are all effectively the same with respect to VOC emission control capabilities. However, in consideration of the negligible 0.01 tpy potential to emit VOC emission rate calculated for the Hot Oil Expansion Tank (D-4203), MRL concluded that it would not be cost effective to install and operate of any of these control technologies on the process vessel. Additionally, the add-on control technologies would require electricity and/or fuel to operate, which would likely result in the emission of combustion pollutants, such as NOx and CO2, into the atmosphere. Furthermore, several of the control technologies would result in the generation of waste streams. For these reasons, MRL eliminated the add-on control technologies from consideration as the maximum air pollution control capability for the vessel's VOC emissions.

Step 5: Select BACT
MRL determined that proper equipment design and operating practices represents the maximum air pollution control capability for VOC emissions from the Hot Oil Expansion Tank (D-4203). Therefore, MRL will control VOC emissions from the Hot Oil Expansion Tank (D- 4203) by properly designing and operating the process vessel.

PTU Blowdown Drum (D-4208)
The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is presented below.

VOC
The PTU Blowdown Drum (D-4208) will periodically receive renewable feed and renewable feed-water mixtures due to PTU equipment maintenance and PTU turnaround events. VOC emissions will occur due to the volatilization of organic compounds from the material handled by the vessel.

The process vessel will not be subject to an NSPS or NESHAP VOC emission standard.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for the PTU Blowdown Drum (D-4208).

Thermal Oxidation

Catalytic Oxidation

Absorption

Carbon Adsorption

Condensation

Below, the available technologies are generally described.

Thermal Oxidation
Please see page 13 for a discussion of this technology.

Catalytic Oxidation
Please see page 13 for a discussion of this technology.

Absorption
Please see page 51 for a discussion of this technology.

Carbon Adsorption
Please see page 50 for a discussion of this technology.

Condensation
Please see page 51 for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options
Below, we evaluate the technical feasibility of the VOC emission control technologies determined to be available for the PTU Blowdown Drum (D-4208).

Thermal Oxidation
This option is technically feasible.

Catalytic Oxidation
This option is technically feasible.

Absorption
This option is technically feasible.

Carbon Adsorption
This option is technically feasible.

Condensation
This option is technically feasible.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The available add-on VOC emission control technologies for the PTU Blowdown Drum (D- 4208) are all effectively the same with respect to VOC emission control capabilities. The different technologies do however have varying energy requirements (e.g., electricity and fuel) and generate unique waste products (e.g., wastewater, solid waste, or combustion emissions).

Step 4: Evaluate Most Effective Control Options
As noted above, the available add-on VOC emission control technologies are all effectively the same with respect to VOC emission control capabilities. Although the uncontrolled potential to emit VOC emission rate calculated for the PTU Blowdown Drum (D-4208) will be negligible, MRL will install a carbon adsorption control device to minimize the vessel's VOC emissions.

Step 5: Select BACT
MRL determined that carbon adsorption represents the maximum air pollution control capability for VOC emissions from the PTU Blowdown Drum (D-4208). Therefore, MRL will control VOC emissions from the vessel by equipping it with a carbon adsorption control device.

PTU Piping Fugitive Components
The maximum air pollution control capability determination made for these sources pursuant to ARM 17.8.752 is presented below.

VOC
Some of the PTU piping fugitive components (pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flanges or other connectors) will handle material that contains VOC. These components will have the potential to emit VOC if they develop a leak to the atmosphere. For example, valves and pumps can develop leaks because of the degradation or failure of seal systems that are designed to prevent material handled by these components from leaking to the atmosphere. A valve's seal system is associated with its stem, which is used to adjust the valve's position. A pump's seal system is associated with its shaft, which is used to provide the pump's pumping action.

The PTU piping fugitive components will not be subject to an NSPS or NESHAP.

Step 1: Identify Control Technologies
MRL determined that equipment design and leak detection and repair (LDAR) practices are available VOC emission control technologies for the PTU piping fugitive components. A general description of these technologies is provided below.

Equipment Design and LDAR
Equipment design examples used to minimize piping component leaks include: (1) a cap, plug, or second valve on an open-ended line; (2) a dual mechanical seal on a pump; and
(3) a rupture disk assembly on a pressure relief valve. These types of design features are reasonably priced and tend to be relatively easy and efficient to operate and maintain.

LDAR programs are used to identify piping components leaking material at a level warranting component repair (or replacement), and the effectiveness of these programs has been well established throughout many different industries over several decades. The primary features of an LDAR program are leak monitoring frequency, leak detection level, and timely leak repair requirements. A piping component may be checked for leakage by visual, audible, olfactory, or instrument techniques. For example, visual inspections may be used to identify leaks of heavy liquid material from connectors, valves, and pumps.
Alternatively, a portable hydrocarbon detection instrument is typically used to identify (and measure) leaks of gases and light liquid materials from piping components. After a leak is detected, then the leak must typically be repaired within a specific time period, followed by a subsequent leak inspection to ensure the leaking component was properly repaired.

For comparison to these practical equipment designs and LDAR practices, the use of a control device (e.g., flare, thermal oxidizer, carbon adsorption device) to control emissions from hundreds or thousands of connectors, valves, and pumps located across a wide area in a process unit is not reasonably applicable because a substantial amount of piping and ductwork would be required to collect the component leaks, the positive pressure leak collection piping and ductwork would have the potential to leak to the atmosphere, and potentially substantial amounts of collateral combustion emissions or solid waste would be generated by the control device(s). Therefore, this type of collection and control scheme is not further evaluated.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the VOC emission control technologies that were determined to be available for the PTU piping fugitive components is evaluated below.

Equipment Design and LDAR
Equipment design and LDAR will be used for the PTU piping fugitive components. Therefore, this option is technically feasible.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The only remaining available VOC emission control technology for the PTU piping fugitive components is the combination of equipment design and LDAR.

Step 4: Evaluate Most Effective Control Options
The only remaining available VOC emission control technology for the PTU piping fugitive components is the combination of equipment design and LDAR.

Step 5: Select BACT
MRL determined that a combination of equipment design and LDAR represents the maximum air pollution control capability for the PTU piping fugitive component VOC emissions pursuant to ARM 17.8.752. Specifically, MRL will control VOC emissions from the PTU piping fugitive components by complying with the following equipment design and LDAR requirements.

The PTU piping fugitive components will comply with the following requirements.

The components "in VOC service" will comply with the equipment leak provisions found in 40 CFR 60.482–1a through 60.482–10a

PTU Wastewater Components

VOC

The PTU wastewater components may handle wastewater containing hydrocarbons. These components will have the potential to emit VOC. For example, VOC contained in the vapor space of a drain system can be emitted to the atmosphere from an open drain riser, from the surface of a drain's water seal, or by diffusion through a drain's water seal.

The PTU wastewater components will be subject to NESHAP Subpart FF.

Step 1: Identify Control Technologies
MRL determined that equipment design features and equipment monitoring and maintenance practices are available VOC emission control technologies for the PTU wastewater components. A general description of these technologies is provided below.

Equipment Design, Monitoring, and Maintenance
Designing a drain riser with a water seal significantly reduces the ability of the VOC contained in the vapor space of the drain system to be emitted to the atmosphere from the riser. This drain design feature is reasonably priced and tends to be relatively easy and efficient to maintain by periodically monitoring the water seal liquid level and adding water to the seal as necessary. Similarly, equipping a junction box with a tightly sealed cover and a relatively small vent pipe effectively limits the amount of VOC that may be emitted from the junction box. Also, junction boxes are usually easily accessible for periodic inspection to ensure the cover is properly positioned and the tight seal around the edge of the cover is maintained.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the VOC emission control technologies that were determined to be available for the PTU wastewater components is evaluated below.

Equipment Design, Monitoring, and Maintenance
Equipment design, monitoring, and maintenance will be used for the PTU wastewater components. Therefore, this option is technically feasible.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The only remaining available VOC emission control technology for the PTU wastewater components is the application of proper equipment design, monitoring, and maintenance.

Step 4: Evaluate Most Effective Control Options
The only remaining available VOC emission control technology for the PTU wastewater components is the application of proper equipment design, monitoring, and maintenance.

Step 5: Select BACT
MRL determined that a combination of equipment design features and equipment monitoring, and maintenance practices represents the maximum air pollution control capability for the PTU wastewater component VOC emissions pursuant to ARM 17.8.752. Specifically, MRL will control VOC emissions from the PTU wastewater components by complying with the following equipment design feature and equipment monitoring and maintenance practices requirements.

- The PTU wastewater components will comply with the following requirements.

- The PTU "individual drain systems," "oil-water separators," and "aggregate facilities" will comply with the provisions found in 40 CFR 60.692–1 through 60.692–7 of NSPS Subpart QQQ.

The components will comply with NESHAP Subpart FF.

Loading - Renewable Kerosene/Sustainable Aviation Fuel.

VOC

The Loading - Renewable Kerosene/Sustainable Aviation Fuel activity represents the loading of renewable kerosene or sustainable aviation fuel into railcars. Loading renewable kerosene or sustainable aviation fuel into a railcar will have the potential to result in VOC emissions to the atmosphere because of the displacement of VOC-containing vapor present in the railcar. Specifically, as renewable kerosene or sustainable aviation fuel is loaded into the railcar, the VOC laden vapor space in the railcar will be displaced and emitted directly to the atmosphere if a vapor collection system is not used during the loading operation.

The Loading - Renewable Kerosene/Sustainable Aviation Fuel activity will not be subject to an NSPS or NESHAP VOC emission standard.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for the Loading - Renewable Kerosene/Sustainable Aviation Fuel activity:

Thermal Oxidation

Catalytic Oxidation

Absorption

Carbon Adsorption

Condensation

Submerged Fill Loading

Below, these technologies are generally described.

Thermal Oxidation
Please see page 13 for a discussion of this technology.

Catalytic Oxidation
Please see page 13 for a discussion of this technology.

Absorption
Please see page 50 for a discussion of this technology.

Carbon Adsorption
Please see page 50 for a discussion of this technology.

Condensation
Please see page 51 for a discussion of this technology.

Submerged Fill Loading
Please see page 35 herein for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the VOC emission control technologies determined to be available for the Loading Renewable Kerosene/Sustainable Aviation Fuel activity is evaluated below.

Thermal Oxidation
This option is technically feasible.

Catalytic Oxidation
This option is technically feasible.

Absorption
This option is technically feasible.

Carbon Adsorption
This option is technically feasible.

Condensation
This option is technically feasible.

Submerged Fill Loading
Submerged fill loading will be an integral component of the operation of the loading activity. Therefore, this option is technically feasible for the activity.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The available add-on VOC emission control technologies for the Loading - Renewable Kerosene/Sustainable Aviation Fuel activity are all effectively the same with respect to VOC emission control capabilities. Alternatively, the submerged fill loading option would not be as effective as the add-on VOC emission control options.

Step 4: Evaluate Most Effective Control Options
As noted above, the available add-on VOC emission control technologies are all effectively the same with respect to VOC emission control capabilities. The different add-on control device technologies do however have varying energy requirements (e.g., electricity and fuel) and generate unique waste products (e.g., wastewater, solid waste, and combustion emissions).
MRL estimated that the installation of piping, associated equipment (e.g., valves and instrumentation), and a thermal oxidizer to collect and control the Loading - Renewable Kerosene/Sustainable Aviation Fuel activity's VOC emissions would cost at least $1,250,000, which is not cost effective in consideration of the minor 1.17 tpy VOC emission rate calculated for the activity.59 Additionally, annual operating costs (e.g., fuel, electricity, maintenance labor, and maintenance materials) required to operate and maintain the add- on control technology would make it even less cost-effective. Therefore, MRL eliminated a vapor collection system and control device from consideration as the maximum air pollution control capability for the activity's VOC emissions.

Step 5: Select BACT
MRL determined that submerged fill loading represents the maximum air pollution control capability for the VOC emissions from the Loading - Renewable Kerosene/Sustainable Aviation Fuel activity. Therefore, MRL will control VOC emissions from the loading activity by performing submerged fill loading.

Loading - PTU Wastewater

VOC
The Loading - PTU Wastewater activity represents the loading of PTU wastewater into tank trucks or railcars. Loading PTU wastewater into these vessels will have the potential to result in VOC emissions to the atmosphere because of the displacement of VOC-containing vapor present in the vessels. Specifically, as PTU wastewater is loaded into a vessel, the VOC laden vapor space in the vessel will be displaced and emitted directly to the atmosphere if a vapor collection system is not used during the loading operation.

The Loading - PTU Wastewater activity will not be subject to an NSPS or NESHAP VOC emission standard.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for the Loading - PTU Wastewater activity:

Thermal Oxidation

Catalytic Oxidation

Absorption

Carbon Adsorption

Condensation

Submerged Fill Loading

Below, these technologies are generally described.

Thermal Oxidation
Please see page 13 for a discussion of this technology.

Catalytic Oxidation
Please see page 13 for a discussion of this technology.

Absorption
Please see page 50 for a discussion of this technology.

Carbon Adsorption
Please see page 50 for a discussion of this technology.

Condensation
Please see page 51 for a discussion of this technology.

Submerged Fill Loading
Please see page 36 herein for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the VOC emission control technologies determined to be available for the Loading PTU Wastewater activity is evaluated below.

Thermal Oxidation
This option is technically feasible.

Catalytic Oxidation
This option is technically feasible.

Absorption
This option is technically feasible.

Carbon Adsorption
This option is technically feasible.

Condensation
This option is technically feasible.

Submerged Fill Loading This option is technically feasible.
Step 3: Rank Remaining Control Technologies by Control Effectiveness
The available add-on VOC emission control technologies for the Loading - PTU Wastewater activity are all effectively the same with respect to VOC emission control capabilities.
Alternatively, the submerged fill loading option would not be as effective as the add-on VOC emission control options.

Step 4: Evaluate Most Effective Control Options
As noted above, the available add-on VOC emission control technologies are all effectively the same with respect to VOC emission control capabilities. Although the uncontrolled potential to emit VOC emission rate calculated for the Loading - PTU Wastewater activity is considerably low, MRL will install a carbon adsorption control device to minimize VOC emissions from the loading activity.

Step 5: Select BACT
MRL determined that carbon adsorption represents BACT for VOC emissions from the Loading - PTU Wastewater activity. Therefore, MRL will control VOC emissions from the loading activity by installing and operating a carbon adsorption control device.

IV. Emission Inventory

To better describe the proposed emission changes occurring with this application, the following table presents the potential to emit from the earlier issued MAQP #5263-00, and the emissions being permitted under MAQP #5263-01, as well as the resulting changes between these permit versions. In every case except for SO_2, the additional equipment being added under MAQP #5263-01 results in minor increases in emissions. SO_2 emissions decrease under MAQP #5263-01 due to MRL accepting lower limits on the concentration of H_2S in some of the heaters.

	Potential to Emit (TPY)		
Pollutant	**MAQP #5263-00**	**MAQP #5263-01**	**Associated Change (TPY)**
CO	51.62	65.5	13.88
NOx	71.08	79.67	8.59
PM (filterable only)	2.09	2.47	0.38
PM_{10} (filt.+ cond.)	7.31	8.61	1.3
$PM_{2.5}$(filt.+ cond.)	7.24	8.54	1.3
SO_2	8.21	5.65	-2.56
VOC	80.63	95.53	14.9

Once all of the equipment is constructed and operating, the facility PTE is shown in the below table. The facility inventory indicates MRL will be below PSD thresholds for all permitted equipment.

MRL Great Falls Renewable Fuels Plant Regulated PSD Pollutant Potential to Emit Summary			
Pollutant	**Potential to Emit (tpy)**	**PSD Major Source Threshold[6] (tpy)**	**Subject to PSD Review (Yes/No)**
CO	65.50	100	No
NOx	79.67	100	No
PM (filterable only)	2.47	100	No
PM_{10}	8.61	100	No
$PM_{2.5}$	8.54	100	No
SO_2	5.65	100	No
VOC	95.53	100	No
GHGs, as CO_2e[7]	N/A	N/A	N/A

V. Existing Air Quality

As of July 8, 2002, Cascade County is designated as an Unclassifiable/Attainment area for all criteria pollutants.

VI. Ambient Air Impact Analysis

From a conventional pollutants standpoint, the emissions increases associated with the Renewable Feed Flexibility Project are minor decreases over the previously permitted levels for the MRL Great Falls Renewable Fuels Plant Projected increases over MAQP #5263-00 are less than 15 tpy each of the pollutants.

The Department determined that the project-related VOC, PM_{10}, $PM_{2.5}$, NO_2, and CO emissions will not cause or contribute to a violation of a federal or state ambient air quality standard.

VII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment.

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

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

VIII. Environmental Assessment

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

Analysis Prepared By: Craig Henrikson
Date: May 16, 2022

DEPARTMENT OF ENVIRONMENTAL QUALITY
Air, Energy & Mining Division
Air Quality Bureau
P.O. Box 200901, Helena, Montana 59620
(406) 444-3490

Montana Renewables LLC

Environmental Assessment for

Montana Air Quality Permit #5263-01

Air Quality Bureau

APPLICANT: Montana Renewables LLC (MRL)		
SITE NAME: MRL Great Falls Renewable Fuels Plant		
PROPOSED PERMIT NUMBER: Montana Air Quality Permit Number 5263-01		
APPLICATION DATE: Received on 04/26/2022, Application Deemed Complete on 05/19/2022		
LOCATION: Lat/Long 47.522981, -111.295454		**COUNTY: Cascade**
PROPERTY OWNERSHIP:	**FEDERAL ____ STATE ____ PRIVATE _X___**	
EA PREPARER:	**Craig Henrikson**	
EA Draft Date	**EA Final Date**	**Permit Final Date**
05/26/2022	**06/21/2022**	**07/07/2022**

COMPLIANCE WITH THE MONTANA ENVIRONMENTAL POLICY ACT

The Montana Department of Environmental Quality (DEQ) prepared this Environmental Assessment (EA) in accordance with requirements of the Montana Environmental Policy Act (MEPA). An EA functions to determine the need to prepare an EIS through an initial evaluation and determination of the significance of impacts associated with the proposed action. However, an agency is required to prepare an EA whenever, as here, statutory requirements do not allow sufficient time for the agency to prepare an EIS (ARM 17.4.607.3.c). This document may disclose impacts over which DEQ has no regulatory authority.

COMPLIANCE WITH THE CLEAN AIR ACT OF MONTANA

The state law that regulates air quality permitting in Montana is the Clean Air Act of Montana, §§ 75-2-101, *et seq*., (CAA) Montana Code Annotated (MCA). 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 project is subject to approval by the DEQ Air Quality Bureau (AQB) as the potential project emissions exceed 25 tons per year for regulated pollutants (ARM 17.8.743.1.e). DEQ's approval of an air quality permit application does not relieve MRL from complying with any other applicable federal, state, or county laws, regulations, or ordinances. MRL is responsible for obtaining any other permits, licenses, or approvals (from DEQ or otherwise) that are required for any part of the proposed project.

Any action DEQ takes at this time is limited to the pending air quality permit application currently before DEQ's AQB and the authority granted to DEQ under the CAA of Montana—it is not indicative of any other action DEQ may take on any future (unsubmitted) applications made pursuant to any other authority (*e.g.* Montana's Water Protection Act). DEQ will decide whether to issue the pending air quality permit pursuant to the requirements of the CAA of Montana alone. DEQ may not withhold, deny, or impose conditions on the permit based on the information contained in this Environmental Assessment. § 75-1-201(4), MCA.

SUMMARY OF THE PROPOSED ACTION: MRL has applied for a Montana air quality permit under the CAA of Montana for the following equipment. The permit action has been assigned Montana Air Quality Permit (MAQP) Number 5263-01. The proposed project would allow MRL to construct and operate a pretreatment unit which would allow lower quality raw materials to be processed at the site and add the ability to produce renewable kerosene and sustainable aviation fuel at the site. The proposed project would result in additional emissions due to the new and transferred equipment and therefore requires a modification to their existing MAQP. MRL was previously permitted under MAQP #5263-00 to install and operate equipment for the production of renewable fuels, and this revised MAQP expands MRL's capabilities to include pretreatment of raw materials and production of renewable kerosene and sustainable aviation fuel. The project for MAQP #5263-01 is identified as the Renewable Feed Flexibility Project.

Table 1: Proposed Action Details

Summary of Proposed Action	
General Overview	MRL's air quality permit application consists of the following new equipment and equipment transfers: Pretreatment Unit (PTU) including Deaerator, liquid-liquid separator, and blowdown process vessels Liquid reactors Heat exchangers Filters and static mixers; and Piping and piping components (pumps, valves, flanges, connectors, etc.). Hot Oil System including: Hot Oil Heater (H-4201) and Hot Oil Expansion Tank (D-4203 – Process Vessel)) PTU Wastewater Handling including: Tank #4201 Truck loading facility Railcar loading facility RDU side stripper for renewable kerosene production Piping (pumps, valves, flanges, connectors) and heat exchangers to handle and cool renewable kerosene

	Process vessels in the RDU to perform filtration, coalescence and drying of renewable kerosene Four new storage tanks to store renewable kerosene and sustainable aviation fuel (SAF) Tank #306 for storing renewable kerosene Tank #307 for storing renewable kerosene Tank #308 for storing renewable kerosene or sustainable aviation fuel Tank #309 for storing renewable kerosene or sustainable aviation fuel Tank #0801 for storing conventional diesel that will be blended with renewable diesel during railcar loading operations. MHC Fractionator Feed Heater (H-4102) (Transferred from Calumet Montana "Refining, LLC (CMR) (Now identified as RDU Fractionator Feed Heater (H-4102)) The facility would be permitted to emit from this equipment until MRL requested permit revocation or until the permit were revoked by DEQ due to gross non-compliance with the permit conditions.
Proposed Action Estimated Disturbance	
Disturbance	Disturbance for construction would be approximately 3-5 acres. Disturbance after construction would be approximately 3-5 acres.
Proposed Action	
Duration	**Construction:** Construction or commencement could start within three years of issuance of the final air quality permit otherwise the authority to construct expires. **Construction Period:** The construction period could begin as soon as the air quality permit (and any other required permits) were in place. Seasonal construction activities are allowed once a Department Application Completeness Determination has been issued. **Operation Life:** Renewable fuels equipment would be expected to last at least thirty years.
Construction Equipment	Typical construction equipment, including cranes, earth moving equipment (bulldozer, grader, frontend loader, trackhoe, etc.), forklifts, telehandlers, boring and drilling rigs.
Personnel Onsite	**Construction:** Approximately 200 to 300 construction personnel were originally indicated for MAQP #5263-00 but has resulted in up to 500 personnel on site. Construction needs for MAQP #5263-01 are likely to require an average of between 300 to 400 workers being on site. **Operations:** MAQP #5263-00 estimated ten to twenty new permanent staff during operation, and with MAQP #5263-01 up to an additional 30 permanent hourly employees are expected. Some additional professional staff hiring may also occur.
Location and Analysis Area	**Location**: The proposed project is located on existing property with an address of 1900 10th Street NE, Great Falls Montana 59404. This parcel is located within

	Section 1 of Township 20 North, Range 03 East. Adjacent and within the existing CMR Great Falls Refinery footprint as specified in Figure 1. Areas bordered in red represent disturbance areas and transferred equipment. **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.
Air Quality	The Draft EA will be attached to the Preliminary Determination Air Quality Permit which would include all enforceable conditions for operation of the emitting units
Conditions incorporated into the Proposed Action	The conditions developed in the Decision (Air Quality Permit) of the Montana Air Quality Permit dated June21, 2022, set forth in Sections II.A-D.

Emission estimates for the project are located in Section IV. Emission Inventory in the Permit Analysis.

Two tables are shown in Section IV, the original PTE for the initial project under MAQP #5263-00, and the revised PTE for MAQP #5263-01 as well as the proposed emission changes occurring between the two permit versions. For MAQP #5263-01, the Renewable Feed Flexibility Project would provide for the following emission changes:

	Potential to Emit (TPY)		
Pollutant	**MAQP #5263-00**	**MAQP #5263-01**	**Associated Change (TPY)**
CO	51.62	65.5	13.88
NOx	71.08	79.67	8.59
PM (filterable only)	2.09	2.47	0.38
PM_{10} (filt . + cond.)	7.31	8.61	1.3
$PM_{2.5}$(filt. + cond.)	7.24	8.54	1.3
SO_2	8.21	5.65	-2.56
VOC	80.63	95.53	14.9

The site emissions for all pollutants would be less than 100 tons per year (tpy) with the highest emission level being VOCs, secondly, oxides of nitrogen (NOx) and third, carbon monoxide (CO). Particulate matter species and sulfur dioxide (SO_2) would each be less than 10 tpy.

The proposed action would be located on private land, within the City of Great Falls, Montana. All information included in the EA is derived from the permit application, discussions with the applicant,

analysis of aerial photography, topographic maps, consultation with DEQ staff, and other research tools.

PURPOSE AND BENEFIT FOR PROPOSED ACTION: DEQ's purpose in conducting this environmental review is to act upon MRL's air quality permit application (MAQP #5263-01) for the purpose of treating raw materials and also to be able to produce renewable kerosene and sustainable aviation fuel in addition to the previously permitted renewable products including renewable diesel and renewable naphtha. These new processes must be permitted as they generate emissions regulated by DEQ.

The benefits of the proposed action, if approved, would allow MRL to construct and operate the proposed equipment at the proposed site to generate renewable fuel products for market. Authority to operate the proposed equipment would continue until the permit was revoked, either at the request of MRL or by DEQ because of non-compliance with the conditions within the air quality permit.

As the project scope has only changed slightly from the previous EA for MAQP #5263-00, the previous EA's conclusions are still largely representative for the revisions under the Renewable Feed Flexibility Project as the previous EA was completed less than 9 months ago. Any changes will be highlighted within this EA. MAQP #5263-01 provides enhancements to the original project design permitted in MAQP #5263-00 and ultimately the facility will be a renewable fuels production facility.

REGULATORY RESPONSIBILITIES: In accordance with ARM 17.4.609(3)(c), DEQ must list any federal, state, or local, authorities that have concurrent or additional jurisdiction or environmental review responsibility for the proposed action and the permits, licenses, and other authorizations required.

MRL must conduct its operations according to the terms of its permit, the CAA of Montana, §§ 75-2-101, *et seq*., MCA, and ARMs 17.8.101, *et seq*.

Upon review of the MRL air quality permit application when combined with HAP emissions from CMR Great Falls Refinery, a Title V permit would be required as both operations are under the common ownership of Calumet Specialty Products Partners, L.P. and the properties are contiguous and/or adjacent.

No other permit applications have been submitted by MRL to DEQ at the time of this EA. MRL is a subsidiary of Calumet Specialty Products Partners, L.P. However, CMR also a subsidiary of Calumet Specialty Products Partners, L.P. had previously submitted an air quality permit application to transfer the equipment identified within the MRL air quality permit application (MAQP #5263-00). The CMR application requested removal of the equipment to be transferred from the existing MAQP #2161-35. The revised CMR MAQP was issued under MAQP #2161-36. Once the transferred equipment and new equipment commissioned under MAQP #5263-00 and MAQP #5263-01 is complete, the transferred equipment would be removed from MAQP #2161-36 under a future permit action. If for any reason, the MRL project was not completed, the transferred equipment would remain eligible for operation under MAQP #2161-36. The exact details of this transfer are covered in MAQP #2161-36. In addition, CMR has also submitted a new application to modify MAQP #2161-36 but that request is unrelated to the permit actions occurring with the issuance of MAQP #5263-01.

MRL must cooperate fully with, and follow the directives of any federal, state, or local entity that may have authority over the MRL Great Falls Renewable Fuels Plant. These permits, licenses, and other authorizations may include: City of Great Falls, Cascade County Weed Control Board, OSHA (worker safety), DEQ AQB (air quality) and Water Protection Bureau groundwater and surface water discharge; stormwater, and MDT and Cascade County (road access).

MRL has requested the air quality permit would use property that is currently owned by CMR. New processing equipment would also be constructed and operated on this same site. The parcel identified is a 44.46 acre site located adjacent to the Missouri River as well as adjacent to the City of Great Falls Wastewater Treatment Plant. MAQP #5263-00 estimated up to 12 acres of disturbance, and the MAQP #5263-01 changes would provide for an additional 3-5 acres of additional disturbance to accommodate the Renewable Feed Flexibility Project.

Figure 1: Map of general location of the proposed project.

EVALUATION AND SUMMARY OF POTENTIAL IMPACTS TO THE PHYSICAL AND HUMAN ENVIRONMENT IN THE AREA AFFECTED BY THE PROPOSED PROJECT:

The impact analysis will identify and evaluate direct and secondary impacts. Direct impacts are those that occur at the same time and place as the action that triggers the effect. Secondary impacts means "a further impact to the human environment that may be stimulated or induced by or otherwise result from a direct impact of the action." ARM 17.4.603(18). Where impacts are expected to occur, the impacts analysis estimates the duration and intensity of the impact.

The duration of an impact is quantified as follows:

- **Short-term**: Short-term impacts are defined as those impacts that would not last longer than the proposed operation of the site.
- **Long-term**: Long-term impacts are defined as impacts that would remain or occur following shutdown of the proposed facility.

The severity of an impact 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. TOPOGRAPHY, GEOLOGY AND SOIL QUALITY, STABILITY AND MOISTURE:

The site is located on the north-side of the Missouri River on Calumet Montana Refining property adjacent to the river. The parcel proposed for the MRL operation is located approximately 370 feet from the river's edge. The elevation is approximately 3,323 feet as referenced by the nearest topographic map on the Montana DEQ GIS website which has a topographic elevation marked very close to the Burlington Northern Santa Fe railway track.

The Calumet Montana Refinery (Site or CMR) is located on Pleistocene age glacial lake deposits, which overlie the consolidated Kootenai Formation. Lemke (1977) calls these sediments Deposits of Glacial Lake Great Falls. Lemke (1977) describes two subunits as an upper stratigraphic unit consisting predominantly of non-plastic fine sand and silt and a lower stratigraphic unit consisting mostly of laminated to non-laminated plastic clay and minor amounts of silt. Previous investigation activities at the CMR facility have documented the presence of unconsolidated Pleistocene fluvial and lake deposits and various fill material at the surface and immediately beneath the Site. These surficial units have been encountered at variable depths across the site that range as much as 10 to 20 ft below ground surface. The Pleistocene deposits are generally saturated but yield minimal quantities of water to wells because of their low hydraulic conductivity (Wilke 1983). (Directly from MRL – email dated 8/31/2021 from Casey Mueller).

Underlying the Pleistocene glacial lake deposits is the Cretaceous-age Kootenai formation that has been differentiated into the fifth (upper) and fourth (lower) members. The fifth member of the Kootenai formation is encountered sitewide immediately beneath the surficial Pleistocene deposits and/or fill material and is distinguished by red-weathered mudstone that contains lenses and beds of brownish-gray and greenish-gray, cross-bedded, micaceous sandstone and light gray nodular limestone concretions. The lower part contains a dark-gray shale and lignite bed with a significant pre-angiosperm flora. The bottom of the Kootenai formation's upper member occurs at 60-100 feet below ground level near the Site. Groundwater in this unit beneath the site occurs under semi-confined conditions.

Direct Impacts: The information provided above is based on the information that DEQ had available to it at the time of completing this EA and provided by the applicant as part of the permit application detailing the proposed site. Available information includes the permit application, analysis of aerial photography, topographic maps, and other research tools. None of the planned disturbance at the site is considered first time disturbance. Soils would be disturbed during construction and operation of the proposed action. MAQP #5263-00 estimated approximately 12 acres of disturbance would occur for the life of the project and MAQP #5263-01 estimated an additional 3-5 acres of disturbance. There is no impact expected to topography and geology.

Secondary Impacts: No secondary impacts to topography, geology, stability, and moisture would be expected.

2. WATER QUALITY, QUANTITY, AND DISTRIBUTION:

The Missouri River is approximately 370 feet to the south. No wetlands have been identified on the site. There is a long narrow parcel of property owned by CMR between the parcel proposed for the MRL facility and the Missouri River. Available information includes the permit application, analysis of aerial photography, topographic maps, and other research tools.

Direct Impacts: The information provided above is based on the information that DEQ had available to it at the time of completing this EA and provided by the applicant for the purpose of obtaining the pending air quality permit. MRL has not submitted any water quality or MPDES permit applications to DEQ. MRL has indicated within the application that additional permits are not planned except for a renewal for their wastewater pretreatment permit with the City of Great Falls (Wastewater Treatment Plant). This permit limits the allowable discharge of flow, pH, solids and metals from the CMR/MRL site as well as oil and grease. Based on communication with MRL, the permit limits are not expected to change with the addition of the MRL equipment but must be updated to reflect the additional process equipment connected to the wastewater system related to MAQP #5263-00. Based on this information, DEQ does not anticipate an impact to surface water features and water quality, quantity, and distribution management. Wastewater generated from the PTU will not be commingled with the wastewater from the rest of the facility. All PTU wastewater will be shipped directly off-site using railcars.

Six new storage tanks are planned for the Renewable Feed Flexibility Project. This includes one for wastewater, four for various renewable products and one for conventional diesel.

Precipitation and surface water would generally be expected to infiltrate into the subsurface, however, any surface water that may leave the site could carry sediment from the disturbed site. Soil disturbances and storm water during construction would be managed under the Montana Pollutant Discharge Elimination System (MPDES) General Permit for Storm Water Discharges associated with construction activity as MRL would be required for construction and potentially during operations. The applicant would need to obtain authorization to discharge under the General Permit for Storm Water Discharges associated with construction activity prior to ground disturbance. MRL would manage erosion control using a variety of Best Management Practices (BMP) including but not limited to non-draining excavations, containment, diversion and control of surface run off, flow attenuation, revegetation, earthen berms, silt fences, and gravel packs. This plan would minimize any stormwater impacts to surface water in the vicinity of the project. The proposed action could require MRL to obtain a stormwater discharge plan during construction and potentially during operations. This plan would minimize any stormwater impacts to surface

water in the vicinity of the project.

No fragile or unique water resources or values are present. Impacts to water quality and quantity, which are resources of significant statewide and societal importance are not expected.

Secondary Impacts: No secondary impacts to water quality, quantity and distribution would be expected. No secondary impacts from storm water runoff would be expected.

3. AIR QUALITY:

As of July 8, 2002, Cascade County is designated as an Unclassifiable/Attainment area for all criteria pollutants according to 40 CFR 81.327. Any new stationary source falling under one of the 28 source categories listed in the "major stationary source" definition at ARM 17.8.801(22) would be a major stationary source if it emits, or has the potential to emit, 100 tpy or more of any regulated Prevention of Significant Deterioration (PSD) pollutant, except for (greenhouse gases) GHGs. The plant would be a "chemical process plant", which is one of the 28 source categories. Therefore, the PSD major source threshold for the plant is 100 tpy. Historical wind patterns at the Great Falls International Airport which is located 4.6 miles to the southwest from MRL, indicates prevailing westerly winds from February thru October, and November thru January winds are most often from the south. A local micro-climate along the Missouri flowing directly to the east would also provide a tendency for easterly air flow.

Direct Impacts: Emissions expected from the proposed action as submitted in the air quality permit application received on April 26, 2022, are shown in Table 2 below. The emissions presented represent the combined emissions that would occur not only from the Renewable Feed Flexibility Project but also from all of the permitted equipment at MRL. The total emission inventory is shown because MAQP #5263-01 includes equipment that is still under construction which was authorized under MAQP #5263-00. This summary concludes that the entire MRL facility remains below the PSD major source threshold of 100 tpy.

Table 2: Renewable Fuels Plant Pollutant Potential to Emit Summary

MRL Great Falls Renewable Fuels Plant Regulated PSD Pollutant Potential to Emit Summary			
Pollutant	**Potential to Emit (tpy)**	**PSD Major Source Threshold[6] (tpy)**	**Subject to PSD Review (Yes/No)**
CO	65.50	100	No
NOx	79.67	100	No
PM (filterable only)	2.47	100	No
PM_{10}	8.61	100	No
$PM_{2.5}$	8.54	100	No
SO_2	5.65	100	No
VOC	95.53	100	No
GHGs, as CO_2e^7	N/A	N/A	N/A

As each pollutant is less than 100 tpy, the proposed facility would not be a major PSD facility. No analysis of greenhouse gases is required for a non-major PSD facility.

Dust particulate would be produced or become airborne during site preparation and construction. Air quality standards, set by the federal government and DEQ AQB and enforced by the AQB, allow for pollutants at the levels permitted within the air quality permit. During construction, heavy equipment and site staging activities would result in emissions from heavy equipment but would cease once construction was completed. Once the site is fully constructed, emissions from the renewable fuels plant would include particulate matter (PM) species, oxides of nitrogen (NOx), carbon monoxide (CO), sulfur dioxide (SO_2), carbon dioxide (CO_2.) Residual volatile organic compounds (VOCs) would leak as fugitives from piping, valves, pumps and other process piping. Project emissions assume the process equipment operates 8,760 hours per year. Air pollution control equipment must be operated at the maximum design for which it is intended ARM 17.8.752(2). Limitations would be placed on the allowable emissions for the renewable fuels plant. As part of the air quality permit application, MRL submitted a Best Available Control Technology (BACT) analysis for each emitting unit. These proposed limits were reviewed and incorporated into MAQP #5263-01 as federally enforceable conditions. These permit limits cover NOx, VOCs, particulate matter and CO with associated ongoing compliance demonstrations, as required by the Department.

Some fugitive road dust may occur on the access routes to the construction areas. Pursuant to ARM 17.8.304(2), fugitive dust emissions would need to meet an operational visible opacity of standard or 20 percent or less averaged over 6 consecutive minutes. Pursuant to ARM 17.8.308(1), MRL is required to take reasonable precautions to control emissions of airborne particulate matter from all phases of operation including material transport. Reasonable precautions would include items such the use of water during construction periods to minimize dust emissions. Air quality standards are also regulated by the federal Clean Air Act, 42 U.S.C. 7401 *et seq.* (1970) and Montana's Clean Indoor Air Act, Mont. Code Ann. § 50-40-101 *et seq.*, and are implemented and enforced by DEQ's AQB. As stated above, MRL is required to comply with all applicable state and federal laws.

CMR has also submitted an application to the Air Quality Bureau which is under review by the Department. The CMR permit application asked for some minor changes to existing permit conditions in MAQP #2161-36. The changes being reviewed for the CMR application are not related to the MRL Renewable Feed Flexibility Project.

For all the above reasons, impacts to air quality from the proposed project are anticipated to be short-term and minor.

Secondary Impacts: Criteria pollutants that would be released disperse into the atmosphere and travel with the wind direction, decreasing in concentration as the pollutants are diluted with ambient air. Concentrations of these pollutants would not be allowed to exceed ambient air quality standards where the public has access which usually is considered to be the property boundary of the industrial facility. Therefore, DEQ does not anticipate impacts to air quality in the area outside the property boundary including the adjacent areas of the City of Great Falls.

4. VEGETATION COVER, QUANTITY AND QUALITY:

There are no known rare or sensitive plants or cover types present in the site area. No fragile or unique resources or values, or resources of statewide or societal importance, are present. Petroleum refining has been conducted at this site since the early 1920's. An air quality permit for the site was first issued in 1985. The Department conducted research using the Montana Natural Heritage Program (MTNHP) website and ran the query titled "Environmental Summary Report" dated August 24, 2021. The proposed action is located at an existing refinery in an urban and industrial setting where the vegetation is limited. The Department did not re-run the MTNHP report since the previous report was less than 9 months old.

Direct Impacts: The information provided above is based on the information that DEQ had available to it at the time of completing this EA and provided by the applicant. Available information includes the permit application, analysis of aerial photography, topographic maps, geologic maps, soil maps, and other research tools. As the proposed project would be located on the existing Calumet Refinery site, the vegetation is very limited at the site. No impacts to vegetation cover, quantity and quality would be expected.

Secondary Impacts: Land disturbance at the site would leave little bare ground not occupied by tanks and process equipment.

5. TERRESTRIAL, AVIAN AND AQUATIC LIFE AND HABITATS:

Petroleum refining has been conducted at this site since the early 1920s. As described earlier in Section 4. Vegetation Cover, the larger polygon area is represented by commercial and industrial operations and the Department conducted research using the Montana Natural Heritage Program (MTNHP) website and ran the query titled "Environmental Summary Report" dated August 24, 2021. However, avian population are not likely to exist on the property due to the existing industrial nature of the property. Avian species may be in the proximity of the proposed project due to the Missouri River.

Direct Impacts: The potential impact (including cumulative impacts) to terrestrial, avian and aquatic life and habitats would be negligible.

A list of species of concern is also identified within in Section 6. Unique, Endangered, Fragile or Limited Environmental Resources as reported from the MTNHP report on unique and endangered resources.

Secondary Impacts: No secondary impacts to terrestrial, avian and aquatic life and habitats stimulated or induced by the direct impacts analyzed above would be expected.

6. UNIQUE, ENDANGERED, FRAGILE OR LIMITED ENVIRONMENTAL RESOURCES:

DEQ conducted a search using the Montana Natural Heritage Program (MTNHP) webpage. As discussed earlier the polygon selected was the 44.46 acre site.

Species of concern (SOC) from the MTNHP identified the following species: Spiny Softshell, Bald Eagle, Great Blue Heron, Golden Eagle, Black Crowned Night-Heron, Black Tern, Common Tern, Swift Fox, Horned Grebe, Ferruginous Hawk, Franklin's Gull, Piping Plover, Foster's Tern, Caspian Tern, American White Pelican, Common Loon, Trumpeter Swan, Harlequin Duck, Sedge

Wren, Black-tailed Prairie Dog, Black-foot Ferret, and Gray-crowned Rosy-Finch. Many of these species listed as SOC have not been observed within the search polygon. The one exception noted is that Bald Eagles have been observed.

Direct Impacts: The majority species of concern from the MTNHP list are associated with the riverine habitat on the Missouri River, which is approximately 370 feet to the south of proposed action. These species would not be displaced by the proposed action as the site is completely industrial and the parcel in question does not contact the river or river banks. The potential impact (including cumulative impacts) to species present including bald eagles would be negligible.

Secondary Impacts: The proposed action would not have secondary impacts to endangered species because the permit conditions are protective of human and animal health.

7. HISTORICAL AND ARCHAEOLOGICAL SITES:

The Montana State Historic Preservation Office (SHPO) was notified of the application. SHPO conducted a file search and provided a letter dated August 25, 2021. The SHPO searched was conducted for Section 1 T20N R3E. Further a review of the project area was conducted by the DEQ archeologist on August 25, 2021. The file search identified 19 cultural resource sites within the search area criteria. After review, nine of the sites were further evaluated due to proximity to the project area. A new SHPO report for MAQP #5263-01 was not requested as the previous report was less than 9 months old.

Direct Impacts: Review of the SHPO report identified three of the 19 sites indicate a potential for impacts to Historic Properties, which is defined as any site that is eligible or potentially eligible to the National Register of Historic Places (NRHP). These are detailed and addressed below.

Site 24CA0656 is a NRHP eligible prehistoric processing site located within less than 300 meters of the project area. The current site status us unknown but given the distance of the project area from the site, there will be no adverse effect to Historic Properties.

Site 24CA0371 is a section of the Cascade County Portion of the Great Northern Railroad which is determined eligible for the NRHP. Though the line exists within the current project boundary, the line will not be physically disturbed, nor does the site retain or rely on aspects of visual integrity that would diminish its eligibility. Therefore, there will be no adverse effects to this Historic Property.

Site 24CA1751 is a historic dump located within the banks of the Missouri River. The site is currently listed as Undetermined for its NRHP status, which qualifies it as a Historic Property until otherwise evaluated. The site is outside of the proposed project area, therefore there will be no adverse effect to this Historic Property.

Due to the limited nature of the proposed disturbance for the project, and the lack of potential from visual elements, there will be no adverse effects to Historic Properties. If resources were discovered during operations resources, it would be MRL's responsibility to determine next steps as required by law.

Secondary Impacts: No secondary impacts to historical and archaeological sites are anticipated.

8. **SAGE GROUSE EXECUTIVE ORDER:**
The project would not be in core, general or connectivity sage grouse habitat, as designated by the Sage Grouse Habitat Conservation Program (Program) at: http://sagegrouse.mt.gov.

Direct Impacts: The proposed action is not located within Sage Grouse habitat, no direct impacts would occur.

Secondary Impacts: No secondary impacts to sage grouse or sage grouse habitat would be expected.

9. AESTHETICS:
The site is located in an area mostly surrounded by industrial private property. Of the 1,280 acres in the larger MTNHP polygon, 1,095 acres are indicated as either private or unknown ownership. The project would occur on private land. The nearest residents to the proposed action reside to the northwest at a distance of approximately 500 feet. There are other houses located directly east of the refinery site starting at about 850 feet from eastern property boundary. It is not expected that the nearest residences to the proposed site would experience any noticeable change in noise levels. Standard noise reducing methods would be employed to minimize the risk that noise levels would rise above current baseline levels. An example of noise minimization would include compressors and pumps being enclosed. The noise levels at the property boundary of the proposed action would not be expected to change.

Direct Impacts: There would be temporary construction with building activities including noise and dust. Equipment planned for construction would likely include cranes, backhoes, graders/dozers, passenger trucks, delivery trucks, cement trucks, and various other types of smaller equipment. The use of the various types of equipment would be spread out over the duration of the expected schedule beginning in the fall of 2022 and continuing into 2023. Once the proposed action is constructed, no discernable change in noise level would be expected. New tanks and other equipment would be visible from Smelter Avenue (Highway 87) located to the north of the refinery property. Impacts would be negligible and short-term. Rail traffic is controlled by Burlington Northern and Santa Fe (BNSF) Railway and is expected to increase with the shipment of PTU wastewater. Truck traffic is expected to increase by 3 trucks per day with rail traffic of 3 railcars per day.

Secondary Impacts: The refinery profile would change slightly with the erection of new tanks and equipment. Noise increases are not expected beyond the proposed action parcel boundary.

10. DEMANDS ON ENVIRONMENTAL RESOURCES OF LAND, WATER, AIR OR ENERGY:
The site is located in an area characterized by heavy industry and commercial businesses.

Direct Impacts: During construction of the proposed action there would be minor increase in energy use to construct the proposed action. Once operational, energy and electric demands would continue for the duration of the facility's lifetime. Renewable fuels would provide fuel for emerging markets where non-fossil fuels are preferred and or required. The MRL production capacity would be approximately 15,000 barrels per day (bpd). See the Air Quality and Water Quality sections of the EA to see the potential impacts from the proposed action regarding Air

and Water resources.

Secondary Impacts: During operations, the proposed action would deliver renewable fuels via railcar and trucks to Canadian and west coast U.S. markets. These shipping deliveries would utilize highway and rail infrastructure for product delivery. Expanded production to include renewable kerosene and sustainable aviation fuel would provide for additional market opportunities.

11. IMPACTS ON OTHER ENVIRONMENTAL RESOURCES:

The site is immediately surrounded by commercial and industrial properties.

Direct Impacts: DEQ did not identify any other nearby activities that may affect the project. Therefore, impacts on other environmental resources are not likely to occur as result of this project.

Secondary Impacts: No secondary impacts to other environmental resources are anticipated as a result of the proposed project.

12. HUMAN HEALTH AND SAFETY:

The applicant would be required to adhere to all applicable state and federal safety laws. Some of the existing employees at Calumet Refining would likely become employees at MRL. The access to the public would be restricted to this property with techniques currently used by the Refinery to limit unrestricted access

Direct Impacts: Impacts to human health and safety are anticipated to be short-term and minor as a result of this project. Tanker and rail car deliveries of feedstock would be made to the site and product shipments of renewable fuels would occur using both truck and rail. Tanker and rail shipping are regulated by other state and federal laws to ensure they are operated safely. This would result in increased tanker traffic on the route to and from the site. When the facility would shut down in the future, the direct impacts would cease to exist.

Secondary Impacts: No secondary impacts to human health and safety are anticipated as a result of the proposed project.

13. INDUSTRIAL, COMMERCIAL AND AGRICULTURAL ACTIVITIES AND PRODUCTION:

The site is currently zoned heavy industrial as is reflected by the existing Calumet refinery and MRL operations, and other industrial and commercial properties. There is no agricultural activity at the site**.** With the proposed project, the MRL capacity would be maintained at approximately 15,000 bpd split across production of all the renewable fuels.

Direct Impacts: A minor decrease on land un-occupied by equipment would occur with approximately 3-5 acres of new disturbance for the proposed action. Most of the rest of the CMR and MRL property is already covered by equipment and access roads on the property. More of the property would be being utilized for industrial production. Impacts on the industrial, commercial, and agricultural activities and production in the area would be minor and short-term. An increase in rail and truck traffic bringing in raw materials including feedstock

such as canola oil would occur. Shipping of PTU generated wastewater would also result in an increase in tanker and railcar traffic.

Secondary Impacts: No secondary impacts to industrial, commercial, water conveyance structures, and agricultural activities and production are anticipated as a result of the proposed project.

14. QUANTITY AND DISTRIBUTION OF EMPLOYMENT:

Prior to issuance of MAQP #5263-00, there were approximately 187 permanent jobs located at the Calumet Refinery. Some of the existing employees have likely become employees of MRL. The Flexible Fuels Feed Project expands the number of permanent employees that will be required at MRL to operate the PTU process and for the production of additional renewable fuels.

Direct Impacts: New employment opportunities would occur with this project. The proposed project would be expected to have only minor impacts on the distribution of employment. During construction approximately 200 - 300 temporary contractor jobs would be created and after construction approximately 30 to 40 new permanent jobs would remain. The duration of employment would be minor and short-term.

Secondary Impacts: Minor increases in in distribution of employment are anticipated as a result of the proposed project. This would be the result of employment created for tanker truck deliveries of feedstock and product deliveries of renewable fuels

15. LOCAL AND STATE TAX BASE AND TAX REVENUES:

The proposed action would be expected to have minor impacts on the local and state tax base and tax revenue. The construction project would provide approximately 300 temporary contractor jobs after which approximately 30 to 40 permanent jobs would be created. Some additional professional staffing jobs may also be created.

Direct 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 this operation.

Secondary Impacts: No secondary impacts to local and state tax base and tax revenues are anticipated as a result of the proposed action.

16. DEMAND FOR GOVERNMENT SERVICES:

The proposed action is in a heavy industrial and commercial area.

Direct Impacts: Compliance review and assistance oversight by DEQ AQB would be conducted in concert with other area activity when in the vicinity. Occasional increases in construction-related traffic would occur but this would only last for the duration of the construction project estimated from the fall of 2022 thru 2023. Oversight by DEQ AQB would be minor and short-term.

Secondary Impacts: Local traffic would likely increase with the new permanent employees and feedstock and product transportation. Impacts would be short-term and minor.

17. LOCALLY ADOPTED ENVIRONMENTAL PLANS AND GOALS:

A review was conducted of the City of Great Falls website on August 25, 2021 for MAQP #5263-00. A zoning map was located and the proposed project would be located on an I-2 Heavy Industrial Zone parcel. Additional review of the City's Planning page revealed a Growth Policy was completed in 2013. Other Planning documents were also viewed one of which was a Missouri River Urban Corridor Plan (Plan). This document was dated 2004. The MRL property near the Missouri River is unlikely to be an area where the preservation of river frontage is addressed by the Plan. The website was again visited on May 12, 2022, to review whether any new documents are available relative to planning at or near the site. No new information was available.

Direct Impacts: MRL is proposing the Flexible Fuels Feed Project on property which is already zoned as Heavy Industrial. No impacts from the proposed action would be expected relative to any locally adopted community planning goals.

Secondary Impacts: No secondary impacts to the locally-adopted environmental plans and goals are anticipated as a result of the proposed action.

18. ACCESS TO AND QUALITY OF RECREATIONAL AND WILDERNESS ACTIVITIES:

The current site of the proposed action is in an area of industrial use. Recreation opportunities are located to the south of the proposed action via water-activities on the Missouri River. No wilderness areas or other recreational sites are in the vicinity.

Direct Impacts: There would be no impacts to the access to wilderness activities as none are in the vicinity of the proposed action. Recreationalists on the Missouri River would likely be able to see some of the new tanks. These recreationalists might be river rafters, fishermen and others drawn to the river. The noise would be similar in nature to the existing CMR and existing MRL operations. If a receptor were to increase their distance from the proposed action, noise and visual impacts would decrease. Duration would be expected to be negligible and short-term.

Secondary Impacts: No secondary impacts to access and quality of recreational and wilderness activities are anticipated as a result of the proposed project.

19. DENSITY AND DISTRIBUTION OF POPULATION AND HOUSING:

The proximity of the proposed action to the City of Great Falls would easily be able to handle all housing needs for temporary workers.

Direct Impacts: The project would not add to the population or require additional housing, therefore, no impacts to density and distribution of population and housing are anticipated. The temporary construction workers would use the existing housing in the surrounding communities for the duration of the construction schedule. The 30 to 40 new permanent workers would not be expected to create a housing shortage in the surrounding communities. As identified elsewhere, the construction schedule is estimated to last from the fall of 2022 thru the 2023. The duration of the on-going employment would be minor and short-term.

Secondary Impacts: No secondary impacts to density and distribution of population and housing are anticipated as a result of the proposed action.

20. SOCIAL STRUCTURES AND MORES:

Based on the required information provided by MRL, DEQ is not aware of any native cultural concerns that would be affected by the proposed activity.

Direct Impacts: This proposed action is located on an existing industrial site, no disruption of native or traditional lifestyles would be expected, therefore, no impacts to social structure and mores are anticipated.

Secondary Impacts: No secondary impacts to social structures and mores are anticipated as a result of the proposed operations.

21. CULTURAL UNIQUENESS AND DIVERSITY:

Based on the required information provided by MRL, DEQ is not aware of any unique qualities of the area that would be affected by the proposed activity.

Direct Impacts: No impacts to cultural uniqueness and diversity are anticipated from this project.

Secondary Impacts: No secondary impacts to cultural uniqueness and diversity are anticipated as a result of the proposed project.

22. PRIVATE PROPERTY IMPACTS:

The proposed project would take place on privately-owned land. The analysis done in response to the Private Property Assessment Act indicates no impact. DEQ does not plan to deny the application or impose conditions that would restrict the regulated person's use of private property so as to constitute a taking. (See Attached Private Property Assessment Act (PPAA) Checklist. Further, if the application is complete, DEQ must take action on the permit pursuant to § 75-2-218(2), MCA. Therefore, DEQ does not have discretion to take the action in another way that would have less impact on private property—its action is bound by a statute.

There are private residences in the area of the proposed project. The closest residence is located approximately 500 feet to the northwest from the western property boundary. Other residences are located approximately 850 feet directly to the east from the eastern property boundary.

23. OTHER APPROPRIATE SOCIAL AND ECONOMIC CIRCUMSTANCES:

Due to the nature of the proposed action, no further direct or secondary impacts are anticipated from this project.

ADDITIONAL ALTERNATIVES CONSIDERED:

No Action Alternative: In addition to the proposed action, DEQ is considering 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.

Other Ways to Accomplish the Action:

In order to meet the project objective of producing renewable fuel products, specific raw materials and energy inputs are necessary, and while the configuration for these processes could be modified for a different physical layout, the relative disturbed area and energy inputs and therefore the associated emissions would not be substantially different than the proposed action.

If the applicant demonstrates compliance with all applicable rules and regulations as required for approval, the "no action" alternative would not be appropriate. Pursuant to, § 75-1-201(4)(a), (MCA) DEQ "may not withhold, deny, or impose conditions on any permit or other authority to act based on" an environmental assessment.

CUMULATIVE IMPACTS:

Cumulative impacts are the collective impacts on the human 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 preimpact statement studies, separate impact statement evaluation, or permit processing procedures. There is currently an air quality permit application from CMR requesting some minor changes to permitting conditions. There are currently no other permit applications for this facility pending before DEQ. Although additional permits may be necessary for this facility in the future, without a pending permit application containing the requisite information, DEQ cannot speculate about which permits may be necessary or which permits may be granted or denied. For example, at this time DEQ does not have sufficient information to determine whether or not a MPDES permit would be required although MRL does not anticipate needing one, and therefore cannot predict whether there would be a discharge associated with this facility. There may, therefore, be additional cumulative impacts (*e.g.* to water) associated with this facility in the future, but those impacts would be analyzed by future environmental reviews associated with those later permitting actions. (For example, if MRL applies for a MPDES permit DEQ will analyze the cumulative impacts of the already issued air quality permit and the then-pending MPDES permit.) This environmental review analyzes only the proposed action submitted by MRL, which is the air quality permit regulating the emissions from the equipment as listed in the "proposed action" section, above.

There are other sources of industrial emissions in the vicinity. CMR is known to have emissions including CO, VOCs, SO_2, NOx and particulate matter and currently operates under MAQP #2161-36. These emissions are limited thru enforceable conditions within their air quality permit. There is also the City of Great Falls Wastewater Treatment facility that like any treatment plant would have emissions. The Wastewater Plant operates under MAQP #4176-00 and has limits in place for both NOx and VOCs. Additionally, there is an incinerator operated in the area by the Montana Highway Patrol. MAQP #5174-00 is held by the Montana Highway Patrol for the purpose of destruction of drugs. The Highway Patrol incinerator is approximately 0.7 mile away. The incinerator is restricted on particulate matter emissions and opacity. Finally, Grain Craft (MAQP #2885-01) operates a flour milling operation to the southeast which is approximately 0.8 mile away and is limited only on opacity. Collectively, these sources and the proposed action can all contribute to the ambient air quality and when future permit actions occur at either MRL or CMR. These actions may require future analysis, depending upon the magnitude of future emission increases. Since the proposed action (even when the equipment previously permitted under MAQP

#5263-00 is included) is not major for PSD, a review of existing permitted sources is not required. The proposed action would not be expected to have any discernable impact as the emission increases remain below PSD thresholds. No change in the EPA air quality designation would be expected. As of July 8, 2002, Cascade County was designated as an Unclassifiable/Attainment area for all criteria pollutants.

A review was also conducted of the City of Great Falls Growth Policy which appears to have been updated in 2013. Several elements which are addressed in the Growth Policy include provisions to guide land-use, transportation, economic development, housing needs and population projections.

DEQ considered potential impacts related to this project and potential secondary impacts. Due to the limited activities in the analysis area, cumulative impacts related to this project would be minor and short-term. The cumulative table for any direct and secondary impacts is located at the very end of this EA in Table III. Those cumulative impacts are also highlighted here regardless of the probability identified in Table III.

Soils would be disturbed to for staging equipment and for constructing concrete pads. The disturbance for construction would cease after all of the equipment was installed. Fugitive dust following construction would likely be limited to road dust from vehicle traffic.

Air quality would not be expected to deteriorate or change from its current classification of Unclassifiable/Attainment for all criteria pollutants. The proposed action is not a PSD action as the project increases for the entire MRL facility would be less than 100 tpy. The MRL facility remains at a capacity of approximately 15,000 bpd of renewable fuels. Emissions of NOx and CO are also minimized through the use of ultra-low NOx burners along with continuous emission monitors for NOx and oxygen (O_2). VOC tank emissions are minimized through application of BACT on the seven new tanks.

Historical and archaeologic sites are known to exist near the proposed project but not expected to be encountered due to the long history of crude oil refining on the site. Any excavation that would result in any significant findings would need to be investigated before further work continued.

Changes in aesthetics for the proposed project would not be expected to materially change the characteristics at the site. The site is already characterized as industrial in nature and includes large visible heaters and equipment. Typical engineering design for noise minimization would be incorporated to prevent excessive noise migration from the site.

Exposure to industrial equipment would be similar in nature to the hazards already occurring under the CMR and MRL permits. Some additional railcar and truck unloading for feedstock such as canola oil would occur. Additional shipments of PTU wastewater on trucks and rail would also occur.

The existing parcel where the project would be constructed will almost entirely be occupied by equipment either operated by MRL or by CMR. Any future construction projects at the site which would require a significant footprint, would be limited by the remaining physical space on the site. Calumet does own other adjacent parcels in the area and these plots would be candidates for future projects.

Based on the application submitted by MRL, both a temporary increase in workforce as well as permanent increase in workforce would be expected for the overall Calumet parent company. Some employees currently working at CMR would be expected to shift over to employment at MRL.

PUBLIC INVOLVEMENT:

Scoping for this proposed action consisted of internal efforts to identify substantive issues and/or concerns related to the proposed operation. Internal scoping consisted of internal review of the environmental assessment document by DEQ Air Permitting staff.

Internal efforts also included queries to the following websites/ databases/ personnel:
- Montana State Historic Preservation Office
- Montana Department of Environmental Quality (DEQ)
- Cascade County Website
- Montana Natural Heritage Program
- Montana Cadastral Mapping Program

OTHER GOVERNMENTAL AGENCIES WITH JURSIDICTION:

The proposed project would be fully located on privately-owned land. All applicable local, state, and federal rules must be adhered to, which, at some level, may also include other local, state, federal, or tribal agency jurisdiction. Other Governmental Agencies which May Have Overlapping or Sole Jurisdiction include, but may not be limited to: City of Great Falls, Cascade County Commission or County Planning Department (zoning), Cascade County Weed Control Board, OSHA (worker safety), DEQ AQB (air quality) and Water Protection Bureau (groundwater and surface water discharge; stormwater), DNRC (water rights), and MDT and Cascade County (road access).

NEED FOR FURTHER ANALYSIS AND SIGNIFICANCE OF POTENTIAL IMPACTS

Under ARM 17.4.608, DEQ is required to determine the significance of impacts associated with the proposed action. This determination is the basis for the agency's decision concerning the need to prepare an environmental impact statement and also refers to DEQ's evaluation of individual and cumulative impacts. DEQ is required to consider the following criteria in determining the significance of each impact on the quality of the human environment:

1. The severity, duration, geographic extent, and frequency of the occurrence of the impact;

   "Severity" is analyzed as the density of the potential impact while "extent" is described as the area where the impact is likely to occur. An example could be that a project may propagate ten noxious weeds on a surface area of 1 square foot. In this case, the impact may be a high severity over a low extent. If those ten noxious weeds were located over ten acres there may be a low severity over a larger extent.

   "Duration" is analyzed as the time period in which the impact may occur while "frequency" is analyzed as how often the impact may occur. For example, an operation that occurs throughout the night may have impacts associated with lighting that occur every night (frequency) over the course of the one season project (duration).

2. 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;

3. Growth-inducing or growth-inhibiting aspects of the impact, including the relationship or contribution of the impact to cumulative impacts;

4. The quantity and quality of each environmental resource or value that would be affected, including the uniqueness and fragility of those resources and values;

5. The importance to the state and to society of each environmental resource or value that would be affected;

6. 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

7. Potential conflict with local, state, or federal laws, requirements, or formal plans.

The significance determination is made by giving weight to these criteria in their totality. For example, impacts with moderate or major severity may be determined to be not significant if the duration of the impacts is considered to be short-term. As another example, however, moderate or major impacts of short-term duration may be considered to be significant if the quantity and quality of the resource is limited and/or the resource is considered to be unique or fragile. As a final example, moderate or major impacts to a resource may be determined to be not significant if the quantity of that resource is high or the quality of the resource is not unique or fragile.

Pursuant to ARM 17.4.607, preparation of an environmental assessment is the appropriate level of environmental review under MEPA if statutory requirements do not allow sufficient time for an agency to prepare an environmental impact statement. An agency determines whether sufficient time is available to prepare an environmental impact statement by comparing statutory requirements that establish when the agency must make its decision on the proposed action with the time required to obtain public review of an environmental impact statement plus a reasonable period to prepare a draft environmental review and, if required, a final environmental impact statement.

SIGNIFICANCE DETERMINATION

The severity, duration, geographic extent and frequency of the occurrence of the impacts associated with the proposed action would be limited. MRL proposes to construct and operate the proposed renewable fuels plant on portions of a CMR parcel located on private land, within the city limits of Great Falls, Montana. The estimated construction disturbance for MAQP #5263-00 was about 12 acres during construction. And the on-going disturbed acreage once operational would also be 12 acres. Once operational, the 12 acres includes the area that would be occupied by new equipment including the large storage tanks. For the revised MAQP #5263-01, an additional 3 to 5 acres of both disturbance and land permanently occupied would occur.

DEQ has not identified any significant impacts associated with the proposed action for any environmental resource. Approving MRL's Air Quality Application would not set precedent that commits DEQ to future actions with significant impacts or a decision in principle about such future actions. DEQ also has received an air quality application from CMR but it is not related to the application for MRL. The CMR application requests some changes to existing permit condition. DEQ is currently processing the CMR application. DEQ would conduct a new environmental review for any subsequent air quality permit applications sought by MRL. DEQ would make a decision on MRL's subsequent application based on the criteria set forth in the CAA of Montana.

DEQ's issuance of an Air Quality Permit to MRL for this proposed operation does not set a precedent for DEQ's review of other applications, including the level of environmental review. The level of environmental review decision is made based on a case-specific consideration of the criteria set forth in ARM 17.4.608.

DEQ does not believe that the proposed action has any growth-inducing or growth-inhibiting aspects or that it conflicts 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, the proposed state action is not predicted to significantly impact the quality of the human environment. Therefore, at this time, preparation of an environmental assessment is determined to be the appropriate level of environmental review under the Montana Environmental Protection Act.

Environmental Assessment and Significance Determination Prepared By:

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Name	**Title**

EA Reviewed By:

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Name	**Title**

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Montana State Historical Preservation Office (SHPO) Report Received August 25, 2021
Montana Natural Heritage Program (Website Search Downloads) Last Download Aug 15, 2021
Montana Cadastral GIS Layer – Through-Out Project Up Until Draft Issuance
Air Quality Bureau Permitted Source List-GIS Layer
Air Quality Permit MAQP #5263-00 and associated EA
Air Quality Permit MAQP #2885-01
Air Quality Permit MAQP #4176-00
Air Quality Permit MAQP #5174-00
Air Quality Permit MAQP #2161-36
City of Great Falls Website – Planning Documents – Reviewed on May 12, 2022
Wind Rose Information – Great Falls International Airport

Table III: Summary of Potential Impacts that could Result from the Renewable Fuels Project (Facility).

Potential Impact	Affected Resource and Section Reference	Severity[1], Extent[2], Duration[3], Frequency[4], Uniqueness and Fragility (U/F)	Probability[5] impact would occur	Cumulative Impacts	Measures to reduce impact as proposed by applicant	Significance (yes/ no)
Soil Disturbance/Fugitive Dust	I. TOPOGRAPHY, GEOLOGY AND SOIL QUALITY, STABILITY AND MOISTURE. II. WATER QUALITY, QUANTITY, AND DISTRIBUTION III. AIR QUALITY	**S**-medium: The 15-18 acre disturbance both during construction and following construction, could be susceptible to erosion and fugitive dust. **E**-medium: Total surface disturbance would be 15-18 acres. **D**-The entire construction project would occur within approximately one to one and half years. There is no existing vegetation on the site. **F**-During occasional moisture events or high wind events. **U/F**-Not unique or particularly fragile.	Certain	The construction period of approximately one to one a half years limits the possible duration and extent of and erosion or fugitive dust. The majority of the site is currently already paved. Once constructed, there would no longer be exposed soils as those areas would be occupied by equipment pads.	MRL would be required to follow reasonable precautions for storm run-off and fugitive dust.	No
VOC, NOx, CO, PM emission release as well as fugitive dust	II. AIR QUALITY	**S**-low: Emissions released from MRL would largely be off-set by decreases occurring at CMR. The Renewable Feed Flexibility Project provides for minor increases over permitted levels in MAQP #5263-00. **E**-small: Total surface disturbance is estimated at 15-18 acres. **D**- The entire construction project would occur within approximately one to one a half years. Emissions from combustion processes would be on-going for the duration of the facility life. **F**-Daily during normal operation **U/F**-Not unique or particularly fragile.	Certain	The emission increases that would occur at MRL would largely be off-set by emission decreases at CMR. Discernable changes in ambient air quality would not be expected.	Emission control technologies such as ultra-low NOx burners, Best Available Control Technology (BACT) limits, federal NESHAP requirements	No

Potential Impact	Affected Resource and Section Reference	Severity[1], Extent[2], Duration[3], Frequency[4], Uniqueness and Fragility (U/F)	Probability[5] impact would occur	Cumulative Impacts	Measures to reduce impact as proposed by applicant	Significance (yes/ no)
Impacts to Historical and Archaeological Sites	III. HISTORICAL AND ARCHAEOLOGICAL SITES:	**S** -low: All areas proposed for disturbance have been previously disturbed. No impact to sites would be anticipated. **E** – low: Site has been petroleum refinery since 1920's. **D** – long-term, any disturbance to archaeological sites would be permanent **F**- Once **U/F**-Not unique or particularly fragile.	Unlikely	Impacts to historical and archaeological sites associated with the project would add to the cumulative impacts associated with any other future developments around the area.	SHPO recommendations would be followed by MRL upon discovery of any historical site significance.	No
Noise increases and visual changes	IV. AESHETICS	**S**-low: Noise increases would not be expected to increase above current baseline. Visual changes would just include more industrial equipment into view from certain locations. **E**-small: The equipment would be installed on the interior of an existing parcel. Not readily accessible to public. **D**- The entire construction project would occur within approximately one to one and half years. Noise and visual changes would be on-going for the duration of the facility life. **F**-Daily: During life of the MRL facility **U/F**-Not unique or particularly fragile.	Possible	Discernable changes in noise would likely not occur. Visual differences would not change the fact the site is already a petroleum refinery and chemical plant.	Equipment would be located away from exterior of property boundary.	No

Energy use increase onsite and transportation energy use increases	V. DEMANDS ON ENVIRONMENTAL RESOURCES OF LAND, WATER, AIR OR ENERGY	**S**-low: Increases in energy use at MRL are mostly off-set by decreases at CMR. **E**-small: Shipping increases at MRL are mostly off-set by decreases at CMR but PTU wastewater shipping will increase. **D**- Energy use at MRL would be on-going for the duration of the facility. **F**-Daily during life of the MRL facility **U/F**-Not unique or particularly fragile.	Certain	Overall energy use would be off-set by the increases at MRL being balanced by the decreases at CMR. A renewable fuels product would be produced for emerging markets where non-fossil derived fuel is required and or preferred.	None proposed	No
Potential Impact	**Affected Resource and Section Reference**	**Severity[1], Extent[2], Duration[3], Frequency[4], Uniqueness and Fragility (U/F)**	**Probability[5] impact will occur**	**Cumulative Impacts**	**Measures to reduce impact as proposed by applicant**	**Significance (yes/ no)**
Traffic Increases and employee exposure to new equipment	VI. HUMAN HEALTH AND SAFETY	**S**-low: Increases in shipping from MRL would largely be off-set by decreases at CMR. Equipment transferred from CMR to MRL would be similar in employee exposure for personnel hazards. **E**-low:. **D**- Traffic and employee personnel impacts would be on-going for the duration of the facility. **F**-Daily during life of the MRL facility **U/F**-Not unique or particularly fragile.	Possible	Overall traffic and personnel impacts would be off-set by the increases at MRL being balanced by the decreases at CMR. Some increase in shipping via railcar and truck would be associated with feedstock including canola oil and for additional truck and rail cars for PTU wastewater.	None proposed.	No
Less bare land at site and increase in amount of land footprint used for diesel production	VII. INDUSTRIAL, COMMERCIAL AND AGRICULTURAL ACTIVITIES AND PRODUCTION	**S** -low: The 15-18-acre disturbance both during construction and following construction. **E** – low: Total surface disturbance would be 15-18 acres. **D** – Duration of the life of the MRL facility **F**- Daily **U/F**-Not unique or particularly fragile.	Certain	Any future projects would be limited by remaining physical space to install new equipment without the demolition of existing equipment.	None proposed.	No
Tax base increase and	VIII. QUANTITY AND	**S** -Medium; Construction workers employed during construction period. Increase in	Certain	Increase in permanently employed workers	None proposed.	No

employment gains	DISTRIBUTION OF EMPLOYMENT	permanent employees across the MRL and CMR sites. **E** – low: Relatively low increase in permanent employees for area. **D** – Duration of the life of the MRL facility **F**- Daily **U/F**-Not unique or particularly fragile				

Definitions are quantified as follows:

- Short-term: Short-term impacts are defined as those impacts that would not last longer than the proposed operation of the site.
- Long-term: Long-term impacts are defined as impacts that would remain or occur following shutdown of the proposed facility.

The severity of an impact 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. Severity describes the density at which the impact may occur. Levels used are low, medium, high.
2. Extent describes the land area over which the impact may occur. Levels used are small, medium, and large.
3. Duration describes the time period over which the impact may occur. Descriptors used are discrete time increments (day, month, year, and season).
4. Frequency describes how often the impact may occur.
5. Probability describes how likely it is that the impact may occur without mitigation. Levels used are: impossible, unlikely, possible, probable, certain

June 22, 2023

Carlos Centurion
Calumet Montana Refining, LLC
1900 10th Street NE
Great Falls, MT 59404

Sent via email: Carlos.Centurion@calumetspecialty.com

RE: **Decision Title V Operating Permit #OP2161-17**

Dear Mr. Centurion:

DEQ prepared this Decision Operating Permit #OP2161-17, for Calumet Montana Refining, LLC, located in Great Falls, Montana. Please review the cover page for information pertaining to the action taking place on this permit.

If you have any questions, please contact Craig Henrikson, the permit writer, at (406) 444-6711 or by email at chenrikson@mt.gov.

Sincerely,

Bo Wilkins
Bureau Chief
Air Quality Bureau
(406) 444-3626

Craig Henrikson, P.E.
Environmental Engineer
Air Quality Bureau
(406) 444-6711

cc: Branch Chief, Air Permitting and Monitoring Branch, US EPA Region VIII 8ARD-PM
Carson Coate, US EPA Region VIII, Montana Office
Robert Gallagher, US EPA Region VIII, Montana Office

AIR QUALITY OPERATING PERMIT #OP2161-17

Significant Modification Application Received:	12/7/2021
Application Deemed Administratively Complete:	02/22/2022
Application Deemed Substantively Complete:	02/22/2022
Draft Issue Date:	03/03/2023
Proposed Issue Date:	05/02/2023
End of EPA 45-day Review:	06/16/2023
Date of Decision:	06/22/2023
Effective Date:	07/25/2023
Expiration Date:	12/10/2025
Complete Renewal Application Due:	06/10/2025
AFS Number: 030-013-0004A	

Calumet Montana Refining, LLC
1900 10th St. NE
Great Falls, MT 59404
NE Quarter of Section 1, Township 20 North, Range 3 East
Cascade County

Calumet is authorized by DEQ to operate a stationary source of air contaminants consisting of the emission units described in this permit (Montana Code Annotated (MCA) Sections 75-2-217 and 218, and the Administrative Rules of Montana (ARM) Title 17, Chapter 8, Subchapter 12, Operating Permit Program, ARM 17.8.1201, *et seq.*).

Calumet is allowed to discharge air pollutants in accordance with the conditions of this permit until it expires, is modified, or is revoked. All conditions in this permit are federally and state enforceable unless otherwise specified. Requirements which are state-only enforceable are identified as such. A copy of this permit must be kept at the facility or a DEQ-approved location.

Permit Issuance and Appeal Process:
This Decision becomes effective on July 25, 2023 (Section 75-2-218, MCA). DEQ will send notification when the permit becomes final.

This Decision may be appealed to the Board of Environmental Review (Board) if a request for a hearing is received by the Board within 30 days of the Decision. The filing of a request for a hearing does not stay the Decision, unless the Board orders a stay (Section 75-2-218(6)(b), MCA).

Petitions may be submitted to the Environmental Protection Agency (EPA) within 60 days after the expiration of the EPA's 45-day review period to object to issuance of this permit (ARM 17.8.1233). If the EPA concurs with the petition, Calumet and all affected parties will be informed of the stay of the Final Permit, and then DEQ shall terminate, modify, or revoke any issued permit (ARM 17.8.1231).

Montana Air Quality Operating Permit
Department of Environmental Quality

Table of Contents

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

SECTION I. GENERAL INFORMATION

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

Company Name: Calumet Montana Refining, LLC (Calumet)

Mailing Address: 1900 10th Street Northeast

City: Great Falls State: MT Zip: 59404

Plant Location: NE¼, Section 1, Township 20 North, Range 3 East, Cascade County

Responsible Official: Mr. Wayne Leiker, V.P. Refining Operations

Facility Contact Person: Joseph Dauner, Environmental Manager

Primary SIC Code: 2911

Nature of Business: Petroleum Refinery

Description of Process: Petroleum refining in Great Falls, Montana. Unit operations include:

- **Crude Distillation** - #1 and #2 Crude Units with atmospheric and vacuum distillation – separating crude oil into component parts (heavier and lighter fractions)
- **Fluidized Catalytic Cracking Unit (FCCU)** – breaking larger chains into smaller chains
- **Catalytic Reformer Unit** – convert lower octane components to high octane reformates
- **Catalytic Poly Unit** – increase lighter, smaller chains into heavier, larger chains
- **Alkylation Unit**– increase lighter, smaller chains into heavier, larger chains
- **Isomerization Unit** – convert linear molecules into higher-octane branched molecules
- **Hydrogen Plants** #1, #2, and #3 – create hydrogen for use in the plant i.e. – hydrotreating and hydrocracking
- **Polymer-Modified Asphalt (PMA) Unit** – heavy asphalt handling including heated tanks
- **Mild Hydrocracker Unit –** rearranging and breaking hydrocarbons, adding hydrogen
- **Hydrotreater Unit** – reducing sulfur and nitrogen content
- **Product Loading –** loading of finished product into cargo tanks
- **Cooling Towers –** cools water used in heat exchangers throughout the process
- **Wastewater Collection and Treatment** – individual drain systems and treatment
- **Boilers –** provides heat via steam for use throughout the process
- **Storage Tanks** - crude oil, intermediates, middle distillates, additives, and products
- **Internal Combustion Engines –** air compression, water pumping, firewater, etc.
- **Flares and Fuel Gas Scrubber Unit –** flares are a control device for hundreds of emissions points throughout the process, and is an important safety device during maintenance, malfunctions and non-steady state conditions such as startup and shutdown. Gas from the process is treated in the fuel gas scrubber unit to reduce sulfur content to minimize SO_2 emissions created during combustion.

SECTION II. SUMMARY OF EMISSION UNITS

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

Title V Section	Description	Pollution Control Device/Practice
#1 Crude Unit		
Section III.C: EU02 – #1 CRUDE UNIT	#1 Crude Atmospheric Heater, H-0101, 30 MMBtu/hr	CD - NSPS J, MACT DDDDD, Burner Management System, NO_X and CO Umbrella Limits
	#1 Crude Vacuum Heater, H-0102, 7 MMBtu/hr	CD - NSPS J, MACT DDDDD, Burner Management System, NO_X and CO Umbrella Limits
	Equipment Components	CD – LDAR, NSPS GGG, MACT CC
	Individual Drain System	NSPS QQQ, MACT CC, NESHAP FF
#2 Crude Unit		
Section III.D: EU03 – #2 CRUDE UNIT	#2 Crude Atmospheric Heater, H-2101, 71 MMBtu/hr	NSPS Ja, MACT DDDDD, Burner Management System, ULNB, NO_X and CO Umbrella Limits
	#2 Crude Vacuum Heater, H-2102, 27 MMBtu/hr	NSPS Ja, MACT DDDDD, Burner Management System, ULNB, NO_X and CO Umbrella Limits
	Equipment Components	CD, NSPS GGGa, MACT CC
	Individual Drain System	NSPS QQQ, MACT CC, NESHAP FF
Catalytic Polymerization Unit		
Section III.E: EU04– Catalytic Polymerization Unit	Equipment Components	MACT CC
	Individual Drain System	NSPS QQQ, MACT CC, NESHAP FF
FCCU		
Section III.F: EU05 – FLUID CATALYTIC CRACKING UNIT (FCCU)	Catalyst Regenerator	MACT UUU, NSPS J via CD,
	FCCU Preheater, H-0302, 8.9 MMBtu/hr	MACT DDDDD, CD NSPS J
	Equipment Components	CD, NSPS GGG, MACT CC
	Individual Drain System	NSPS QQQ, MACT CC, NESHAP FF
Catalytic Reformer and Naphtha Units		
	Reformer Heater, H-0403, 24.2 MMBtu/hr	CD, NSPS J, MACT DDDDD

Title V Section	Description	Pollution Control Device/Practice
Section III.G: EU06 – CATALYTIC REFORMER UNIT and NAPHTHA HYDROTREATING UNIT	Process Vents	MACT CC, MACT UUU
	Equipment Components	MACT CC
	Individual Drain System	NSPS QQQ, MACT CC, NESHAP FF
	Naphtha Heater, H-0402a, 13.6 MMBtu/hr	NSPS Ja, MACT DDDDD
	Naphtha Splitter Reboiler, H-0405, 9.9 MMBtu/hr	NSPS Ja, MACT DDDDD
	Process Vents	MACT CC
	Equipment Components	NSPS GGGa, MACT CC
Alkylation Unit		
Section III.H: EU07 – ALKYLATION UNIT	Deisobutanizer Reboiler, 28 MMBtu/hr	CD, NSPS J, MACT DDDDD
	Equipment Components	MACT CC
	Individual Drain System	NSPS QQQ, MACT CC, NESHAP FF
	Pressure Vessels in HF Service	Flare System
Isomerization Unit		
Section III.I: EU08 – ISOMERIZATION UNIT	Equipment Components	MACT CC
	Individual Drain System	NSPS QQQ, MACT CC, NESHAP FF
Hydrogen Plants		
Section III.J: EU09 – HYDROGEN PLANTS		
H_2 Plant #1		
	#1 H_2 Plant Furnace – H-1801, 23.8 MMBtu/hr	CD, NSPS J, MACT DDDDD
	#1 H_2 Plant Components	CD, NSPS GGG
	#1 H_2 Plant Individual Drain System	NSPS QQQ, MACT CC, NESHAP FF
H_2 Plant #2		
	#2 H_2 Plant Furnace – H-2815, 80 MMBtu/hr	CD, NSPS Ja, MACT DDDDD, ULNB
	#2 H_2 Plant Components	CD, NSPS GGGa
	#2 H_2 Plant Individual Drain System	NSPS QQQ, MACT CC, NESHAP FF
H_2 Plant #3		
	#3 H_2 Plant Furnace A and B (combined stack) – H31A&B, 67 MMBtu/hr each	CD, NSPS Ja, MACT DDDDD, ULNB, Umbrella Limits
	#3 H_2 Plant Components	CD, NSPS GGGa
	#3 H_2 Plant Individual Drain System	NSPS QQQ, MACT CC, NESHAP FF
Polymer-Modified Asphalt Unit		
Section III.K: **EU10 –** POLYMER-MODIFIED ASPHALT UNIT		
	Tank 50	NSPS UU, MACT CC
	Tank 55 - Asphalt	MACT CC
	Tank 55 Heater – 6 MMBtu/hr	CD, NSPS J, MACT DDDDD
	Tank 56 – Asphalt	MACT CC

Title V Section	Description	Pollution Control Device/Practice
	Tank 56 Heater – 9 MMBtu/hr	CD, NSPS J, MACT DDDDD
	Tank 69 - Asphalt	MACT CC
	Tank 102 – Asphalt / NaHS	NSPS UU; MACT CC
	Tank 110 – Asphalt	MACT CC
	Tank 110 Heater – 5 MMBtu/hr	CD, NSPS J, MACT DDDDD
	Tank 112 – Asphalt	MACT CC
	Tank 112 Heater – 5 MMBtu/hr	CD, NSPS J, MACT DDDDD
	Tank 130 – PMA	MACT CC
	Tank 130 Heater – 0.8MMBtu/hr	CD, NSPS J, MACT DDDDD
	Tank 132 – PMA	MACT CC
	Tank 132 Heater – 0.8 MMBtu/hr	NSPS J, MACT DDDDD
	Tank 133 – PMA	MACT CC
	Tank 133 Heater – 0.8 MMBtu/hr	CD, NSPS J, MACT DDDDD
	Tank 135 – Asphalt	MACT CC
	Tank 135 Heater – 6 MMBtu/hr	NSPS J, MACT DDDDD
	Tank 137 – Asphalt	NSPS UU, MACT CC
	Tank 137 Heater – 1.4 MMBtu/hr	NSPS J, NSPS UU, MACT CC
	Tank 138 – Asphalt	NSPS UU; MACT CC
	Tank 138 Heater – 1.4 MMBtu/hr	NSPS Ja, MACT DDDDD
	Tank 139 – Asphalt	NSPS UU; MACT CC
	Tank 139 Heater – 4 MMBtu/hr	NSPS J, MACT DDDDD
	Tank 140 – Asphalt	NSPS UU, MACT CC
	Tank 140 Heater – 4 MMBtu/hr	NSPS J, MACT DDDDD
	Equipment Components	CD, NSPS GGG, MACT CC
	Individual Drain System	MACT CC, NESHAP FF
Mild Hydrocracker Unit		
Section III.L: EU11 – MILD HYDROCRACKER UNIT	MHC Combined Feed Heater, H-4101, 54 MMBtu/hr	CD, NSPS Ja, MACT DDDDD, ULNB, Umbrella Limits
	MHC Fractionator Feed Heater, H-4102, 38 MMBtu/hr	NSPS Ja, MACT DDDDD, ULNB, Umbrella Limits
	Process Vents	MACT CC
	Equipment Components	CD, NSPS GGGa, MACT CC
	Individual Drain System	NSPS QQQ, MACT CC, NESHAP FF
Hydrotreater Unit		
Section III.M: EU12 –	Kerosene Heater	NSPS J, MACT DDDDD

Title V Section	Description	Pollution Control Device/Practice
HYDROTREATER UNIT	HTU Heater, H-1701, 22.5 MMBtu/hr	CD, NSPS J, MACT DDDDD
	Process Vents	MACT CC
	Equipment Components	CD, NSPS GGG, MACT CC
	Individual Drain System	NSPS QQQ, MACT CC, NESHAP FF
Flares and Flare Gas Scrubber Unit		
Section III.N: EU13 – FLARE #1 & #2, Flare Gas Scrubber Equipment Components	Primary Flare #1 – Air Assisted	NSPS Ja, MACT CC, Air Assisted, H_2S Scrubbing
	Secondary Flare (Flare #2) – Air Assisted	NSPS Ja, MACT CC, Air Assisted
	NaHS Process Vents	MACT CC
	NaHS Equipment Components	CD, MACT GGGa, MACT CC
	Flare Gas Scrubber	CD, NSPS GGGa/VVa, MACT CC
Product Loading		
Section III.O: EU14 –		
Truck Loading Rack		
	Truck Loading Rack – Gasoline	MACT R, MACT CC
	Truck Loading Rack VCU	MACT R, MAQP BACT
	Truck Loading Rack Equipment Components	MACT CC
	Individual Drain System	NSPS QQQ, MACT CC, NESHAP FF
Railcar Loading Rack		
	Railcar Loading Rack – Gasoline	MACT R, MACT CC
	Railcar Loading Rack – Naphtha	MACT EEEE
	Railcar Loading Rack VCU	MACT R, MAQP BACT
	Railcar Loading Rack Equipment Components	MACT CC
	Individual Drain System	NSPS QQQ, MACT CC, NESHAP FF
Cooling Towers		
Section III.P: EU15 –	North Cooling Tower	Mist Eliminator, Total Dissolved Solids Control, MACT CC
	South Cooling Tower	Mist Eliminator, Total Dissolved Solids Control, MACT CC
Wastewater Collection and Treatment		
Section III.Q: EU16:	Individual Drain Systems, Junction Boxes, and Sampling Devices	NSPS QQQ, MACT CC, NESHAP FF
	API Separator, Aeration Tank, DAF Unit, etc	NSPS QQQ, MACT CC, NESHAP FF
	Closed Vent Systems and Control Devices	NSPS QQQ, MACT CC, NESHAP FF
	External Floating Roof, Wastewater Tanks	NSPS QQQ, MACT CC, NESHAP FF
Boilers		

Title V Section	Description	Pollution Control Device/Practice
Section III.R: EU17:	Boiler #1, B-0701, stack combined with Boiler #2	CD, NSPS J, MACT DDDDD, NO_X and CO Umbrella Limits
	Boiler #2, B-0702, stack combined with Boiler #1	CD, NSPS J, MACT DDDDD, NO_X and CO Umbrella Limits
	Boiler #3, B-0703, 60.5 MMBtu/hr	CD, NSPS Ja, NSPS Dc, MACT DDDDD, ULNB, Flue Gas Recirculation, NO_X and CO Umbrella Limits
	Individual Drain System	NSPS QQQ
Storage Tanks		
Section III.S: EU18:	Tank 1: 152 bbl, Fixed Roof in Jet Fuel Additive service	MACT EEEE
	Tank 2: 800 bbl Pressure Vessel in Propane service	Intrinsic Design
	Tank 3: 2,000 bbl Pressure Vessel in Isobutane service	Intrinsic Design
	Tank 4: 600 bbl Pressure Vessel in Butane service	Intrinsic Design
	Tank 5: 600 bbl Pressure Vessel in Isobutane service	Intrinsic Design
	Tank 10: 375 bbl Fixed Roof tank in Transmix service	MACT CC
	Tank 14: 1,400 bbl Pressure Vessel in Isobutane service	Intrinsic Design
	Tank 15: 1,400 bbl Pressure Vessel in Butane service	Intrinsic Design
	Tank 29: 20,600 bbl Fixed Roof in Distillate service	MACT CC
	Tank 47: 20,500 bbl Fixed Roof in Middle Distillates Service	MACT CC
	Tank 48: 20,500 bbl Fixed Roof in Middle Distillates Service	MACT CC
	Tank 49: 20,500 bbl Fixed Roof in Middle Distillates Service	MACT CC
	Tank 51: 21,000 bbl Fixed Roof in Treated Gas Oil Service	MACT CC
	Tank 52: 19,000 bbl External Floating Roof in Gasoline service	MACT CC, NSPS Kb
	Tank 54: 18,000 bbl Fixed Roof in fire water	Not regulated
	Tank 58: 20,983 bbl Fixed Roof in Middle Distillates Service	MACT CC
	Tank 100: 1,100 bbl Fixed Roof in #5 Fuel Oil or NaHS service	MACT CC
	Tank 101: 1,100 bbl Fixed Roof in #5 Fuel Oil or NaHS service	MACT CC
	Tank 116: 44,900 bbl Fixed Roof in Distillate service	MACT CC
	Tank 118: 2,000 bbl Fixed Roof in Asphalt Emulsion service	MACT CC
	Tank 119: 2,000 bbl Fixed Roof in Asphalt Emulsion service	MACT CC
	Tank 120: 2,200 bbl Fixed Roof in Asphalt Emulsion service	MACT CC
	Tank 121: 2,200 bbl Fixed Roof in Asphalt Emulsion service	MACT CC
	Tank 122: 21,900 bbl External Floating Roof in Gasoline service	MACT CC, NSPS Kb
	Tank 123: 21,900 bbl External Floating Roof in Gasoline service	MACT CC, NSPS Kb
	Tank 124: 21,500 bbl External Floating Roof in Naphtha service	MACT CC, NSPS Kb
	Tank 125: 38,500 bbl Fixed Roof in Heavy Liquids service	MACT CC
	Tank 126: 29,500 bbl External Floating Roof in Gasoline service	MACT CC, NSPS Kb
	Tank 127: 21,500 bbl External Floating Roof in Gasoline service	MACT CC
	Tank 128: 21,500 bbl Fixed Roof in Heavy Liquids service	MACT CC
	Tank 150: 30,100 bbl Fixed Roof in Raw Kerosene service	MACT CC
	Tank 170: 10,200 bbl Fixed Roof in Distillate service	MACT CC
	Tank 171: 10,200 bbl Fixed Roof in Distillate service	MACT CC
	Tank 175: 400 bbl Fixed Roof in Ethanol service	MACT CC

Title V Section	Description	Pollution Control Device/Practice
	Tank 176: 5,000 bbl Internal Floating Roof in Ethanol service	MACT CC, NSPS Kb
	Tank 201: 69,700 bbl External Floating Roof in Crude Oil service	MACT CC, NSPS Kb
	Tank 202: 69,700 bbl External Floating Roof in Crude Oil service	MACT CC, NSPS Kb
	Tank 203: 69,700 bbl External Floating Roof in Crude Oil service	MACT CC, NSPS Kb
	Tank Farm Equipment Components	MACT CC
	Individual Drain System	MACT CC, NSPS QQQ, NESHAP FF
Stationary Internal Combustion Engines		
Section III.T: EU19– EU19a: GEN1 EU19b: AC1 EU19c: WP1 EU19d: WP2 EU19e: WP3 EU19f: WP4	GEN1: 400 hp diesel fired Emergency Generator	NSPS IIII, MACT ZZZZ
	AC1: 540 hp diesel fired Emergency Air Compressor Engine	NSPS IIII, MACT ZZZZ
	WP1: 165 hp, diesel fired Emergency Storm Water Pump	NSPS IIII, MACT ZZZZ
	WP2: 240 hp, diesel fired Tank 54 Emergency Fire Water Pump	MACT ZZZZ
	WP3: 300 hp, diesel fired Tank 24 Emergency Fire Water Pump	NSPS IIII, MACT ZZZZ
	WP4: 300 hp, diesel fired Tank 146 Emergency Fire Water Pump	NSPS IIII, MACT ZZZZ

SECTION III. PERMIT CONDITIONS

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

A. Facility-Wide

Conditions	Rule Citation	Rule Description	Pollutant/Parameter	Limit
A.1	ARM 17.8.105	Testing Requirements	Testing Requirements	-------
A.2	ARM 17.8.106	Source Testing Protocol	Testing, Recordkeeping, and Reporting Requirements	-------
A.3	ARM 17.8.304(1)	Visible Air Contaminants	Opacity	40%
A.4	ARM 17.8.304(2)	Visible Air Contaminants	Opacity	20%
A.5	ARM 17.8.304(3)	Visible Air Contaminants	Opacity	60%
A.6	ARM 17.8.308(1)	Particulate Matter, Airborne	Fugitive Opacity	20%
A.7	ARM 17.8.308(2)	Particulate Matter, Airborne	Reasonable Precautions	-------
A.8	ARM 17.8.308(3)	Particulate Matter, Airborne	Reasonable Precaution, Construction	20%
A.9	ARM 17.8.309	Particulate Matter, Fuel Burning Equipment	Particulate Matter	$E = 0.882 * H^{-0.1664}$ or $E = 1.026 * H^{-0.233}$
A.10	ARM 17.8.310	Particulate Matter, Industrial Processes	Particulate Matter	$E = 4.10 * P^{0.67}$ or $E = 55 * P^{0.11} - 40$
A.11	ARM 17.8.322(4)	Sulfur Oxide Emissions, Sulfur in Fuel	Sulfur in Fuel (liquid or solid fuels)	1 lb/MMBtu fired
A.12	ARM 17.8.322(5)	Sulfur Oxide Emissions, Sulfur in Fuel	Sulfur in Fuel (gaseous)	50 gr/100 CF
A.13	ARM 17.8.324(1)	Hydrocarbon Emissions, Petroleum Products	65,000 Gallon Capacity	-------
A.14	ARM 17.8.324(2)	Hydrocarbon Emissions, Petroleum Products	Oil-effluent Water Separator	-------
A.15	ARM 17.8.324(3)	Hydrocarbon Emissions, Petroleum Products	Gasoline Storage Tanks	-------
A.16	40 CFR 63 Subpart CC	MACT CC Fenceline Monitoring	Benzene	-------
A.17	ARM 17.8.341, 40 CFR Part 61	National Emissions Standards for Benzene Waste Operations	Petroleum Refinery Wide – applicable provisions of 40 CFR 61, Subparts J, M, V & FF	-------
A.18	ARM 17.8.342, 40 CFR Part 63	NESHAPs General Provisions	SSM Plans	Submittal
A.19	ARM 17.8.1211(1)(c) and 40 CFR Part 98 (Not a Title V applicable requirement)	Greenhouse Gas Reporting	Reporting	-------
A.20	ARM 17.8.1212	Reporting Requirements	Prompt Deviation Reporting	---------
A.21	ARM 17.8.615	Firefighting Training Permit	Firefighting Requirements	

Conditions	Rule Citation	Rule Description	Pollutant/Parameter	Limit
A.22	40 CFR Part 68	Chemical Accident Prevention	Risk Management Plan	
A.23	40 CFR 63 Subpart GGGGG	National Emission Standards for Hazardous Air Pollutants for Site Remediation	40 CFR 63 Subpart GGGGG	40 CFR 63 Subpart GGGGG
A.24	CIV-01-1422LH (entered 3/5/02)	Consent Decree	Various	As specified
A.25	ARM 17.8.1212	Reporting Requirements	Compliance Monitoring	-------
A.26	ARM 17.8.1207	Reporting Requirements	Annual Certification	-------

Conditions

A.1. Pursuant to ARM 17.8.105, any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, of Environmental Quality (DEQ) provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct test, emission or ambient, for such periods of time as may be necessary using methods approved by the Department.

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

A.2. Pursuant to ARM 17.8.106, all emission source testing, sampling and data collection, recording analysis, and transmittal must be performed, maintained, and reported in accordance with the Montana Source Test Protocol and Procedures Manual (dated July 1994 unless superseded by rulemaking), unless alternate methods are approved by DEQ. Calumet shall clearly indicate the underlying rule or condition requiring the testing, the last source test date, the testing schedule required by the rule or condition, and a preliminary proposed test date, in any source test protocol submitted. (ARM 17.8.1212).

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

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

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

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

A.7. Pursuant to ARM 17.8.308(2), Calumet shall not cause or authorize the use of any street, road or parking lot without taking reasonable precautions to control emissions of airborne PM, unless otherwise specified by rule or in this permit.

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

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

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

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

Where H is the heat input capacity in million British thermal units (MMBtu) per hour and E is the maximum allowable particulate emissions rate in pounds per MMBtu.

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

For process weight rates up to 30 tons per hour: $E = 4.10 * P^{0.67}$
For process weight rates in excess of 30 tons per hour: $E = 55.0 * P^{0.11} - 40$

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

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

A.12. Pursuant to ARM 17.8.322(5), Calumet shall not burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet (gr/100 CF) of gaseous fuel, calculated as hydrogen sulfide at standard conditions, unless otherwise specified by rule or in this permit. This rule shall be interpreted to mean that no person shall burn solid, liquid, or gaseous fuels such that the aggregate sulfur content of all fuels burned within a plant during any day exceeds 1 pound of sulfur per MMBtu fired. The rule shall be interpreted to allow for a daily deviation of 0.1 pound of sulfur per MMBtu fired. The rule shall be interpreted to allow the blending of all fuels burned in a plant during a given time period in determining the aggregate sulfur content for purposes of the rule, and it shall not be construed to require blending or physical mixing of fuels at any given furnace or heater within the plant complex (EPA-approved SIP, September 1979).

A.13. Pursuant to ARM 17.8.324(1), unless otherwise specified by rule or in this permit, Calumet shall not place, store or hold in any stationary tank, reservoir or other container of more than 65,000-gallon capacity any crude oil, gasoline or petroleum distillate having a vapor pressure of 2.5 pounds per square inch absolute or greater under actual storage conditions, unless such tank, reservoir or other container is a pressure tank maintaining working pressure sufficient at all times to prevent hydrocarbon vapor or gas loss to the atmosphere, or is designed and equipped with a vapor loss control device, properly installed, in good working order and in operation.

A.14. Pursuant to ARM 17.8.324(2), unless otherwise specified by rule or in this permit, Calumet shall not use any compartment of any single or multiple-compartment oil-effluent water separator which compartment receives effluent water containing 200 gallons a day or more of any petroleum product from any equipment processing, refining, treating, storing or handling kerosene or other petroleum product of equal or greater volatility than kerosene, unless such compartment is equipped with a vapor loss control device, constructed so as to prevent emission of hydrocarbon vapors to the atmosphere, properly installed, in good working order and in operation.

A.15. Pursuant to ARM 17.8.324(3), Calumet shall not load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device or is a pressure tank as described in ARM 17.8.324(1), or unless otherwise specified by rule or in this permit.

A.16. Pursuant to 40 CFR 63 Subpart CC, Calumet shall comply with the fenceline monitoring provisions of 40 CFR 63 Subpart CC including electronic reporting requirements.

A.17. Pursuant to ARM 17.8.341 and 40 CFR Part 61, Calumet shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements, contained in the National Emission Standards for Hazardous Air Pollutants (NESHAPS) provisions of 40 CFR 61, Subpart J Equipment Leaks (Benzene), Subpart V Equipment Leaks, Subpart FF Benzene Waste Operations and Subpart M Asbestos. If at any time from the Date of Lodging of the Consent Decree Calumet is determined to have a total annual benzene (TAB) equal to or greater than 10 megagrams per year (Mg/yr), Calumet, as applicable, shall comply with the compliance option set forth at 40 CFR 61.342(e).

A.18. Pursuant to ARM 17.8.302 and ARM 17.8.342, and 40 CFR 63.6, the owner or operator must maintain at the affected source a current startup, shutdown, and malfunction plan (if a plan is required by 40 CFR 63.6(e)(3) and the Table for General Provision Applicability of the appropriate subpart), meeting the requirements of 40 CFR 63.6, and must make the plan available upon request. In addition, if the startup, shutdown, and malfunction plan is subsequently revised, the owner or operator must maintain at the affected source each previous (i.e., superseded) version of the startup, shutdown, and malfunction plan, and must make each such previous version available for a period of 5 years after revision of the plan. The owner or operator shall confirm that actions taken during the relevant reporting period during periods of startup, shutdown, and malfunction were consistent with the affected source's startup, shutdown and malfunction plan in the semiannual (or more frequent) startup, shutdown, and malfunction report required in 40 CFR 63.10(d)(5).

A.19. Pursuant to ARM 17.8.1211(1)(c) and 40 CFR Part 98, Calumet shall comply with requirements of 40 CFR Part 98 – Mandatory Greenhouse Gas Reporting, as applicable (ARM 17.8.1211(1)(c), NOT an applicable requirement under Title V).

A.20. Calumet shall promptly report deviations from permit requirements including those attributable to upset conditions, as upset is defined in the permit. To be considered prompt, deviations shall be reported to DEQ using the schedule and content as described in Section V.E (unless otherwise specified in an applicable requirement) (ARM 17.8.1212).

A.21. Pursuant to ARM 17.8.615, Calumet shall apply for and comply with a Firefighter Training permit to conduct open burning for fire training purposes for any firefighter training.

A.22. Calumet shall comply with all applicable requirements of 40 CFR Part 68 – Risk Management Plan requirements (ARM 17.8.1211 and 40 CFR 68).

A.23. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart GGGGG, National Emission Standards for Hazardous Air Pollutants: Site Remediation. (ARM 17.8.342 and 40 CFR 63 Subpart GGGGG).

A.24. Calumet shall comply with the all applicable terms of US EPA Consent Decree CIV-01-1422LH (entered March 5, 2002), and its Amendments, for the life of the Consent Decree, including the following (ARM 17.8.1211):

a. Section V: Affirmative Relief/Environmental Projects
b. Section VI: Emission Credit Generation
c. Section VII: Modification to Implementation Schedules

d. Section IX: Reporting and Recordkeeping
e. Section XIII: Right of Entry
f. Section XIV: Force Majeure
g. Section XVII: General Provisions
h. Section XVIII: Termination

A.25. On or before February 15 and August 15 of each year, Calumet shall submit to DEQ the compliance monitoring reports required by Section V.D, as described under ARM 17.8.1212. These reports must contain all information required by Section V.D, as well as the information required by each individual emissions unit. For units equipped with CEMS, excess emissions and monitoring downtime percentages reported on a semiannual basis shall be calculated on a quarterly basis. For the reports due by February 15 of each year, Calumet may submit a single report covering both semiannual reporting needs and annual certification needs, provided that it contains all monitoring information reporting required by each emitting unit and the information required by both Section V.B & V.D. Per ARM 17.8.1207,

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

A.26. By February 15 of each year, Calumet shall submit to DEQ the compliance certification report required by Section V.B. The annual certification report required by Section V.B must include a statement of compliance based on the information available, which identifies any observed, documented or otherwise known instance of noncompliance for each applicable requirement. Per ARM 17.8.1207,

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

B. EU01 – PLANT-WIDE LIMITATIONS

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
B.1, B.8, B.16, B.18, B.22, B.23, B.28, B.29	Plantwide SO_2 Emissions	1,515 TPY and 4.15 ton/rolling 24-hours	RFG H_2S monitoring systems, data from the FCCU SO_2 CEMS and the Boilers #1 and #2 SO_2 CEMS, and stack testing data	Ongoing	Semiannual
B.2, B.9, B.16, B.18, B.22, B.24, B.28, B.29	Plantwide CO Emissions	4,700 TPY and 12.9 tons/rolling 24-hours	FCCU CO CEMS and stack testing data, including stack tests of the boilers, product loading VCUs	Ongoing	Semiannual
B.3, B.10, B.19, B.28, B.29	SO_2	No Fuel Oil Combustion	Recordkeeping	Ongoing	Semiannual
B.4, B.11, B.18, B.20, B.22, B.28, B.29	NO_X	NO_X Reduction Technologies	Recordkeeping	Ongoing	Semiannual
B.5, B.12, B.13, B.16, B.17, B.26, B.28, B.29	NO_X	Umbrella Limit: 103.02 TPY	Outlined in each applicable section	Ongoing	Semiannual
B.6, B.14, B.16, B.17, B.26, B.28, B.29	CO	Umbrella Limit: 55.08 TPY	Outlined in each applicable section	Ongoing	Semiannual
B.7, B.15, B.16, B.21, B.27, B.28, B.29	Ambient SO_2 Monitoring	n/a	Appendix E	Ongoing	Semiannual

Conditions

B.1. Calumet shall be limited to maximum plantwide SO_2 emissions of 1,515 TPY on a rolling 12-month sum basis and 4.15 tons/rolling 24-hours (ARM 17.8.749).

B.2. Calumet shall be limited to maximum plantwide CO emissions of 4,700 TPY on a rolling 12-month sum basis and 12.9 tons/rolling 24-hours (ARM 17.8.749).

B.3. Calumet shall not combust fuel oil in any combustion unit (except torch oil may be used in the FCCU Regenerator during FCCU startups as noted in Condition III.F.12) (ARM 17.8.1211 and Consent Decree Section V.17.C.ii).

B.4. Any heater or boiler with a heat input capacity of 40 MMBtu/hr or greater shall have installed and operated Next Generation Ultra Low NO_X Burners on any such heater or boiler. Calumet shall comply with the remaining provisions of Paragraph 16.C – 16.E of this section of the consent decree for any such heater (ARM 17.8.1211, Consent Decree Section V.16.C.iii).

B.5. NO_X emissions from the following units, combined, shall not exceed 103.02 tons per year as determined monthly on a rolling 12-month basis, for purposes of PSD avoidance for NO_X associated with the expansion project as permitted in MAQP #2161-30. With exception of any unit equipped with NO_X CEMS verified via RATA, NO_X emissions shall be determined utilizing emissions factors determined via monthly portable analyzer results for 12 months, after which, emissions factors shall be determined based on source tests. Fuel flow shall be monitored continuously, and heat content of fuel gas determined no less than weekly. The monthly and rolling 12-month sums for the previous month shall be determined and recorded by no later than the 25th of each month. This limit is effective beginning with the first full month following the start of portable analyzer testing. Portable analyzer testing shall begin within 90 days after finalization of MAQP #2161-30 or upon startup of any affected unit, whichever is later (ARM 17.8.749).

- Boiler #1
- Boiler #2
- Crude Unit #1 Atmospheric Heater
- Crude Unit #1 Vacuum Heater
- Boiler #3
- Crude Unit #2 Atmospheric Heater H-2101
- Crude Unit #2 Vacuum Heater H-2102
- Combined Feed Heater H-4101
- MHC Reactor Fractionation Feed Heater H-4102
- #3 Hydrogen Plant Reformer A
- #3 Hydrogen Plant Reformer B

B.6. CO emissions from the following units, combined, shall not exceed 55.08 tons per year as determined monthly on a rolling 12-month basis, for purposes of PSD avoidance for CO associated with the expansion project as permitted in MAQP #2161-30. With exception of any unit equipped with CO CEMS verified via RATA, CO emissions shall be determined utilizing emissions factors determined via monthly portable analyzer results for 12 months, after which, emissions factors shall be determined based on annual source tests. Fuel flow shall be monitored continuously, and heat content of fuel gas determined no less than weekly. The monthly and rolling 12-month sums for the previous month shall be determined and recorded by no later than the 25th of each month. This limit is effective beginning with the first full month following the start of portable analyzer testing. Portable analyzer testing shall begin within 90 days after finalization of MAQP #2161-30 or upon startup of an affected unit, whichever is later (ARM 17.8.749).

- Boiler #1
- Boiler #2
- Crude Unit #1 Atmospheric Heater
- Crude Unit #1 Vacuum Heater
- Boiler #3
- Crude Unit #2 Atmospheric Heater H-2101
- Crude Unit #2 Vacuum Heater H-2102
- Combined Feed Heater H-4101
- MHC Reactor Fractionation Feed Heater H-4102
- #3 Hydrogen Plant Reformer A
- #3 Hydrogen Plant Reformer B

B.7. Calumet shall conduct ambient air monitoring as described in Appendix E of this permit (ARM 17.8.749).

Compliance Demonstration

B.8. Compliance with the plant-wide SO_2 emission limitations contained in Section III.B.1 shall be monitored using data taken from the RFG H_2S monitoring systems required by 40 CFR 60 Subpart J and Ja, in conjunction with metered RFG usage data from the FCCU SO_2 CEMS, the #1 and #2 Boiler SO_2 CEMS, and stack testing data (ARM 17.8.749 and ARM 17.8.1213).

B.9. Compliance with the plant-wide CO emission limitations contained in Section III.B.2 shall be monitored based on data from available CEMS including the FCCU CO CEMS and emission factors developed from stack tests, including stack tests of the boilers, product loading VCUs, and any other stack tests conducted (ARM 17.8.1213).

B.10. Calumet shall maintain records of monthly amounts of fuel oil burned by process unit. A sentence stating no fuel oil was burned throughout the refinery, with exception of that noted, will suffice (ARM 17.8.1213).

B.11. For heaters and boilers with a heat input capacity of equal to or less than 100 mmBtu/hr on a higher heating value basis, Calumet shall, by no later than 60 days after the date of installation of the applicable NO_X Control Technology, conduct an initial performance test and develop representative operating parameters for each unit, which will be used as indicators of compliance. (ARM 17.8.1213, Consent Decree section V.16.C.iii). DEQ will consider NO_X CEMS operated in accord with the requirements of 40 CFR 60 Subpart A and Ja as fulfilling these requirements, for any unit so equipped (ARM 17.8.1213).

B.12. Units Subject to the NO_X Umbrella Limitation of Section III.B.5:

a. Each unit subject to the NO_X umbrella limitation and not equipped with validated (RATA conducted) CEMS meeting 40 CFR 60 Subpart A and Ja requirements, shall have annual Method 7E source tests (or testing as approved by DEQ), with the first source test to be conducted no later than 12 months after finalization of MAQP #2161-30. All testing shall be conducted concurrently with CO testing. Units equipped with

NO_X CEMS shall conduct a RATA as required. Emissions factors in units of lb/MMBtu shall be determined from the most recent emissions testing (portable analyzer test, source test, or performance test (i.e. RATA testing), as applicable (ARM 17.8.749).

b. For any refinery fuel gas fired units subject to the NO_X umbrella limit in which a NO_X CEMS verified via a RATA is not in place, Calumet shall, at least once every calendar month, conduct concurrent NO_X and CO monitoring utilizing a portable analyzer and submit the results in a format as provided by Attachment 2 (MAQP 2161-36) on a quarterly basis (within 45 days of the end of each calendar quarter). Such monitoring must begin no later than 90 days after finalization of MAQP #2161-30, and shall be conducted for no less than 12 consecutive months following finalization of MAQP #2161-30. Any subsequent source test indicating noncompliance with any NO_X or CO limit shall reinstate this requirement, until no less than 4 quarters of compliance is again achieved. Emissions factors in units of lb/MMBtu shall be determined from the most recent emissions testing (portable analyzer test, source test or performance test, as applicable) (ARM 17.8.749).

c. Portable analyzer testing shall not be required in any month in which source testing or performance testing is performed (ARM 17.8.749).

d. Upon demonstrating 12 months of compliance with the umbrella limit, Calumet shall monitor emissions as prescribed for each emitting unit in each respective section of this Title V. For any unit not equipped with NO_X CEMS at the time Title V Permit #OP2161-14 goes final, an emissions factor based on the average of all emissions factors used to date shall be used until the next source test or CEMS data is available (ARM 17.8.1213).

B.13. Crude Heater #2 H-2101, Mild Hydrocracker Heater H-4101, and #3 Hydrogen Plant Reformer Heaters H-3815A and H3815B shall be equipped with NO_X CEMS in compliance with 40 CFR 60 Subpart A and Ja by no later than June 30, 2018 (ARM 17.8.749).

B.14. Units Subject to CO Umbrella Limitation of Section II.B.6:

a. For all units subject to the CO Umbrella Limitation of Section II.B.6 in which a validated CO CEMS is not utilized, Calumet shall test for CO currently with testing for NO_X (ARM 17.8.749). For any units equipped with NO_X CEMS but no CO CEMS, CO testing concurrent with NO_X RATA Testing is acceptable. Units equipped with CO CEMS shall conduct a RATA as required and determine lb/MMBtu emissions factors during the RATA testing (ARM 17.8.749).

b. For any refinery fuel gas fired units subject to the CO umbrella limit in which a CO CEMS verified via a RATA is not utilized, Calumet shall, at least once every calendar month, conduct concurrent NO_X and CO monitoring utilizing a portable analyzer and submit the results in a format as provided by Attachment 2 (MAQP 2161-36) on a quarterly basis (within 45 days of the end of each calendar quarter). Such monitoring must begin no later than 90 days after finalization of MAQP #2161-30 and shall be conducted for no less than 12 consecutive months following finalization of MAQP #2161-30. Any subsequent source test indicating noncompliance with any NO_X or CO

limit shall reinstate this requirement, until no less than 4 quarters of compliance is again achieved (ARM 17.8.749).

c. Upon 12 months of demonstrating compliance with the umbrella limit, Calumet shall monitor emissions as prescribed for each emitting unit in each respective section of this Title V. For any unit not equipped with CO CEMS at the time of Title V Permit #OP2161-14 goes final, an emissions factor based on the average of all previously determined emissions factors shall be used until the next source test and/or CEMS data is available (ARM 17.8.1213).

B.15. Calumet shall submit quarterly reports of ambient monitoring data in accordance with Appendix E (ARM 17.8.1213).

Recordkeeping

B.16. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and EPA and must be submitted to DEQ upon request (ARM 17.8.1212).

B.17. By the 25th day of each month, Calumet shall calculate and record the monthly and rolling 12-month sum of NO_X and CO emissions from each unit subject to the umbrella limitations for the previous month. Calumet shall also calculate and record, by the 25th of each month, the total monthly and rolling 12-month sum of emissions for the units combined for the previous 12 months (ARM 17.8.749 and ARM 17.8.1212).

B.18. All source test recordkeeping shall be performed in accordance with the test methods being used and Section III.A.2 (ARM 17.8.106).

B.19. Calumet shall maintain records of fuel oil usage by amount and unit. A sentence stating no fuel oil was burned throughout the refinery, with exception of as any noted, will suffice (ARM 17.8.1212).

B.20. Calumet shall maintain records of all Heaters and Boilers on which Next Generation Ultra Low NO_X Control Technology as required by the Consent Decree was installed and shall include the following (ARM 17.8.1212 and Consent Decree Section V.16.F):

a. Type of NO_X Control Technology installed with detailed description of manufacturer name and model and designed emission factors;

b. A summary table of test dates, report dates, and results of all performance test conducted on each such heater and boiler;

c. A list of all heaters and boilers scheduled to have NO_X control Technology installed during the next calendar year, the projected date of installation, and type of NO_X Control Technology that will be installed on those units;

d. An identification of proposed and established permit limits applicable to each heater or boiler for which NO_X control technology has been installed.

B.21. Calumet shall keep Ambient Monitoring records in accordance with the requirements of Appendix E of this permit and 40 CFR 60 Appendix F (ARM 17.8.1212).

Reporting

B.22. Any compliance source test reports must be submitted in accordance with Section III.A.2 (ARM 17.8.106 and ARM 17.8.1212).

B.23. Calumet shall provide semiannual reports of plantwide SO_2 actual emissions compared to the emissions limitation of Section III.B.1, using the data collected as required above, that will monitor compliance with the plant-wide emission limits. The semiannual reports shall include the following (ARM 17.8.1212 and ARM 17.8.749):

a. Facility-wide SO_2 emission estimates for each month, including:

i. Refinery fuel gas: daily H2S monitoring data and refinery fuel gas usage;

ii. SO_2 CEMS Data from FCCU, and the #1 and #2 Boilers, converted to daily mass emissions.

b. Compliance source test data used to update emission factors, conducted during the reporting period;

c. Identification of any periods of excess emissions or other excursions during the reporting period;

d. Monitoring downtime that occurred during the reporting period;

e. A summary of flaring events; and

f. A summary of the quarterly Cylinder Gas Audit (CGA) and any daily calibration drift findings.

B.24. Calumet shall provide semiannual reports of plantwide CO actual emissions compared to the emissions limitation of Section III.B.2 (ARM 17.8.1212, ARM 17.8.1213).

B.25. In accordance to the Consent Decree Paragraph IX, Calumet shall, within 30 days after the end of each calendar quarter until termination of the Consent Decree, provide a progress report to contain the implementation of the requirements of Section V, a summary of the emissions data as required by Section V, a description of any problems anticipated with respect to meeting the requirements of Section V, a description of all environmentally beneficial project and implementation activity in accordance with Paragraphs 29-33, and any additional items as necessary (ARM 17.8.1211 and Consent Decree Paragraph IX).

B.26. Calumet shall report monthly and rolling 12-month sums for each unit under the NO_X and CO Umbrella limitations on a semiannual basis. The report shall include the emissions

factor and/or measurement methodology used and monthly and rolling 12-month sums for each unit, and as a sum of all units (ARM 17.8.1213, and ARM 17.8.749 and ARM 17.8.1212).

B.27. Calumet shall submit semiannual reports of ambient monitoring data in accordance with Appendix E (ARM 17.8.1212).

B.28. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1213).

B.29. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. The fuel oil consumption records required by Section III.B.19.
b. Reference to the dates quarterly reports required by this section were submitted.
c. The NO_X reduction technology records required by Section III.B.20, if any updates to those records were made during the semi-annual reporting period; otherwise, reference to the date these records were last submitted.

C. EU02 – #1 CRUDE UNIT

EU02a – #1 Crude Atmospheric Heater, H-0101
EU02b – #1 Crude Vacuum Heater, H-0102
EU02c – Equipment Components
EU02d – Individual Drain System

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
C.1, C.9, C.17, C.33, C.34	H-0101 Stack Height	150 ft above ground level	Recordkeeping	Ongoing	Semiannually
C.2, C.10, C.18, C.26, C.33, C.34	NO_X and CO	Section III.B	Section III.B	Section III.B	Section III.B
C.3, C.11, A.24, C.19, C.27, C.33, C.34	NSPS J – H_2S in fuel gas (SO_2)	0.10 gr/dscf, or alternatively pursuant to 40 CFR 60.100(e), NSPS Ja	Fuel Gas H_2S content CMS in compliance with 40 CFR 60 Subpart J or alternatively, Ja	Continuous	Quarterly and NSPS J
C.4, C.12, C.20, C.28, C.33, C.34	MACT DDDDD: HAPs (CO as surrogate)	40 CFR 63 Subpart DDDDD: Work Practice Standards: Periodic Tune-ups	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	Semiannually and 40 CFR 63 Subpart DDDDD
C.5, C.13, C.21, C.29, C.33, C.34	MACT CC: HAPs from equipment leaks	40 CFR 63 Subpart CC and 40 CFR 60 Subpart VV	40 CFR 63 Subpart CC and 40 CFR 60 Subpart VV	40 CFR 63 Subpart CC and 40 CFR	Semiannually and 40 CFR 63 Subpart CC

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Frequency	Reporting Requirements
				60 Subpart VV	
C.5, C.13, C.21, C.29, C.33, C.34	MACT CC: HAPs from miscellaneous process vents	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannually and 40 CFR 63 Subpart CC
C.6, C.14, C.22, C.30, C.33, C.34	NSPS GGG: VOC from equipment leaks	40 CFR 60 Subpart GGG and 40 CFR 60 Subpart VV	40 CFR 60 Subpart GGG and 40 CFR 60 Subpart VV	40 CFR 60 Subpart GGG and 40 CFR 60 Subpart VV	Semiannually and 40 CFR 60 Subpart GGG
C.7, C.15, C.23, C.31, C.33, C.34	NSPS QQQ: VOC from wastewater system	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	Semiannually and 40 CFR 60 Subpart QQQ
C.8, C.16, C.24, C.32, C.33, C.34	NESHAP FF: Benzene from wastewater system	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	Semiannually and 40 CFR 61 Subpart FF

Conditions

C.1. The #1 crude heater H-0101 stack height shall be at least 150-feet above ground level (ARM 17.8.749).

C.2. Calumet shall comply with the NO_X and CO Umbrella Limitations of Section III.B.5 and III.B.6. The #1 Crude Atmospheric Heater H-0101 and #1 Crude Vacuum Heater H-0102 are affected units under the NO_X and CO Umbrella Limitations (ARM 17.8.1211).

C.3. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart J – Standards of Performance for Petroleum Refineries, including as applicable to the #1 Crude Unit Atmospheric Heater H-0101 and the #1 Crude Unit Vacuum Heater H-0102 fuel gas combustion devices (Consent Decree, ARM 17.8.340, ARM 17.8.302, ARM 17.8.1211, and 40 CFR 60 Subpart J).

C.4. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, including as applicable to the #1 Crude Unit Atmospheric Heater H-0101 and the #1 Crude Unit Vacuum Heater H-0102, "gas category 1" process heaters (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

C.5. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, including compliance with equipment leak standards and referenced requirements in 40 CFR 60 Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for equipment in the #1 Crude Unit, and

miscellaneous process vents within the #1 Crude Unit (ARM 17.8.302, ARM 17.8.342, and 40 CFR 63 Subpart CC).

C.6. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries (ARM 17.8.340, ARM 17.8.302, 40 CFR 60 Subpart GGG).

C.7. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ, including as applicable to the individual drain system of Crude Unit #1 (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, 40 CFR 60 Subpart QQQ).

C.8. Calumet shall comply with all applicable requirements of 40 CFR 61 Subpart FF – National Emissions Standard for Benzene Waste Operations, as applicable to the individual drain system of the #1 Crude Unit (ARM 17.8.1211, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Compliance Demonstration

C.9. Calumet shall monitor compliance with the stack height requirement of Section III.C.1 via maintaining certified as-built drawings on-site. Any change to stack height requires notification as required by ARM 17.8.745 (ARM 17.8.1213).

C.10. For units equipped with NO_X CEMS, Calumet shall monitor compliance with the NO_X and CO umbrella limitation utilizing emissions estimated from NO_X CEMS, and CO emissions from emissions factors determined during source tests to be conducted concurrent with NO_X RATA testing (ARM 17.8.1213).

C.11. Calumet shall monitor compliance with 40 CFR 60 Subpart J as required by 40 CFR 60 Subpart J (ARM 17.8.1213, ARM 17.8.302, ARM 17.8.340, and 40 CFR 60 Subpart J).

C.12. Calumet shall monitor compliance with 40 CFR 63 Subpart DDDDD as required by 40 CFR 63 Subpart DDDDD (ARM 17.8.1213, ARM 17.8.302, ARM 17.8.342, and 40 CFR 63 Subpart DDDDD).

C.13. Calumet shall monitor compliance with 40 CFR 63 Subpart CC as required by 40 CFR 63 Subpart CC (ARM 17.8.1213, ARM 17.8.302, ARM 17.8.342, and 40 CFR 63 Subpart CC).

C.14. Calumet shall monitor compliance with 40 CFR 60 Subpart GGG as required by 40 CFR 60 Subpart GGG (ARM 17.8.1213, ARM 17.8.302, ARM 17.8.340, and 40 CFR 60 Subpart GGG).

C.15. Calumet shall monitor compliance with 40 CFR 60 Subpart QQQ as required by 40 CFR 60 Subpart QQQ (ARM 17.8.1213, ARM 17.8.302, ARM 17.8.340, and 40 CFR 60 Subpart QQQ).

C.16. Calumet shall monitor compliance with 40 CFR 61 Subpart FF as required by 40 CFR 61 Subpart FF (ARM 17.8.1211, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Recordkeeping

C.17. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and EPA and must be submitted to DEQ upon request (ARM 17.8.1212).

C.18. Calumet shall maintain NO_X and CO Umbrella limit emissions records in accord with Section III.B.17 (ARM 17.8.1212).

C.19. Calumet shall maintain records as required by 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, 40 CFR 60 Subpart J).

C.20. Calumet shall maintain records as required by 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, 40 CFR 63 Subpart DDDDD).

C.21. Calumet shall maintain records as required by 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, 40 CFR 63 Subpart CC.

C.22. Calumet shall maintain records as required by 40 CFR 60 Subpart GGG (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, 40 CFR 60 Subpart GGG).

C.23. Calumet shall maintain records as required by 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, 40 CFR 60 Subpart QQQ).

C.24. Calumet shall maintain records as required by 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, 40 CFR 61 Subpart FF).

Reporting

C.25. Any compliance source test reports and/or logs must be submitted in accordance with Section III.A.2 (ARM 17.8.106 and ARM 17.8.1212).

C.26. Calumet shall comply with the NO_X and CO Umbrella limit reporting requirements of Section III.B.26 (ARM 17.8.1212).

C.27. Calumet shall comply with the applicable reporting requirements of 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, 40 CFR 60 Subpart J).

C.28. Calumet shall comply with the applicable reporting requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, 40 CFR 63 Subpart DDDDD).

C.29. Calumet shall comply with the applicable reporting requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, 40 CFR 63 Subpart CC).

C.30. Calumet shall comply with the applicable reporting requirements of 40 CFR 60 Subpart GGG (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, 40 CFR 60 Subpart GGG).

C.31. Calumet shall comply with the applicable reporting requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, 40 CFR 60 Subpart QQQ).

C.32. Calumet shall comply with the reporting requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, 40 CFR 61 Subpart FF).

C.33. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1213).

C.34. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. A summary of the results of any source testing that was performed during the reporting period and date the report was submitted;

b. A summary of any changes made to stack height of H-0101, or statement that no changes have been made;

c. Summary demonstrating compliance status with 40 CFR 60 Subpart J including reference to submittal dates of reports made or included;

d. Summary demonstrating compliance status with 40 CFR 63 Subpart DDDDD including reference to submittal dates of reports made or included;

e. Summary demonstrating compliance status with 40 CFR 63 Subpart CC including reference to submittal dates of reports made or included;

f. Summary demonstrating compliance status with 40 CFR 60 Subpart GGG including reference to submittal dates of reports made or included;

g. Summary demonstrating compliance status with 40 CFR 60 Subpart QQQ including reference to submittal dates of reports made or included;

h. Summary demonstrating compliance status with 40 CFR 61 Subpart FF including reference to submittal dates of reports made or included.

D. EU03 – #2 CRUDE UNIT

EU03a - #2 Crude Atmospheric Heater H-2101
EU03b - #2 Crude Vacuum Heater H-2102
EU03c - #2 Crude Unit Equipment Components
EU03d - #2 Crude Unit Individual Drain System

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
D.1, D.15, D.29, D.27, D.45, D.46	Max Capacity of H-2101	71.0 MMBtu/hr	Recordkeeping	Ongoing	Semiannual
D.2, D.15, D.29, D.27, D.45, D.46	Max Capacity of H-2102	27.0 MMBtu/hr	Recordkeeping	Ongoing	Semiannual
D.3, D.16, D.27, D.28, D.45, D.46	H-2101 NO_X	0.035 lb/MMBtu, 30-day rolling	CEMS	Continuous	Semiannual

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Frequency	Reporting Requirements
		average BACT limit			
D.4, D.17, A.2, D.27, D.28D.45, D.46	H-2102 NO_X	0.040 lb/MMBtu, average of three source test runs	Method 7E	Annually	Semiannual and Section III.A.2
D.5, D.18, A.2, D.27, D.45, D.46	H-2101 CO	0.055 lb/MMBtu BACT limit	Source Testing once per year during a NO_X RATA	Annually	Semiannual and Section III.A.2
D.5, D.18, A.2, D.27, D.45, D.46	H-2102 CO	0.055 lb/MMBtu BACT limit	Source Testing once per year during a NO_X RATA	Annually	Semiannual and Section III.A.2
D.6, D.16, D.18, D.30, D.38, D.45, D.46	H-2101 NO_X and CO Umbrella Limit	Umbrella Limit	NO_X CEMS and annual CO testing during RATA	Continuous	Semiannual and Section III.A.2
D.6, D.16, D.18, D.30, D.38, D.45, D.46	H-2102 NO_X and CO Umbrella Limit	Umbrella Limit	NO_X CEMS and annual CO testing during RATA	Continuous	Semiannual and Section III.A.2
D.7, D.19, D.27, A.2, D.45, D.46	PM, PM_{10}	0.00051 lb/MMBtu BACT limit	Method 201 and 202	As required by DEQ and Section III.A.1	Semiannual and Section III.A.2
D.7, D.19, D.27, A.2, D.45, D.46	$PM_{2.5}$	0.00042 lb/MMBtu BACT limit	Method 201 and 202	As required by DEQ and Section III.A.1	Semiannual and Section III.A.2
D.8, D.20, D.27, D.45, D.46	CO_2e	142 lb/MMBtu based on a 30-day rolling average BACT limit	Recordkeeping of emissions based on fuel usage and established emissions factors	Ongoing	Semiannual
D.9, D.21, D.27, D.32, D.39, D.45, D.46	NSPS Ja H_2S/SO_2 for fuel gas combustion devices. NSPS Ja NO_X for H-2101 – 0.040 lb/MMBtu on a 30-day rolling average basis, or, 40 ppmvd on a 30-	SO_2: H_2S content of Fuel Gas CMS NO_X: 40 CFR 60 Subpart Ja CEMS option	40 CFR 60 Subpart Ja	Continuous	Semiannual and 40 CFR 60 Subpart Ja

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
	day rolling average basis, 0% O_2.				
D.10, D.22, D.27, D.33, D.45, D.46	HAPs from Process Heaters: 40 CFR 63 Subpart DDDDD (CO as surrogate)	40 CFR 63 Subpart DDDDD Work Practice Standards: Periodic Tune-ups	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	Semiannual and 40 CFR 63 Subpart DDDDD
D.11, D.23, D.34, D.41, D.45, D.46	HAPs from equipment leaks: 40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
D.11, D.23, D.34, D.41, D.45, D.46	HAPs from process vents: 40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
D.12, D.24, D.35, D.42, D.45, D.46	VOC from equipment leaks: 40 CFR 60 Subpart GGGa	40 CFR 60 Subpart GGGa	40 CFR 60 Subpart GGGa	40 CFR 60 Subpart GGGa	Semiannual and 40 CFR 60 Subpart GGGa
D.13, D.25, D.36, D.43, D.45, D.46	VOC from wastewater systems	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	Semiannual and 40 CFR 60 Subpart QQQ
D.14, D.26, D.37, D.44, D.45, D.46	Benzene emissions from wastewater	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	Semiannual and 40 CFR 61 Subpart FF

Conditions

D.1. The maximum rated capacity of the #2 Crude Atmospheric Heater H-2101 shall not exceed 71.0 MMBtu/hr (ARM 17.8.1211 and ARM 17.8.749).

D.2. The maximum rated capacity of the #2 Crude Vacuum Heater H-2102 shall not exceed 27.0 MMBtu/hr (ARM 17.8.1211 and ARM 17.8.749).

D.3. The #2 Crude Unit Atmospheric Heater H-2101 shall be equipped with ULNB and NO_X emissions shall not exceed 0.035 lb/MMBtu-HHV based on a 30-day rolling average (ARM 17.8.1211, ARM 17.8.752).

D.4. The #2 Crude Unit Vacuum Heater H-2102 shall be equipped with ULNB and NO_X emissions shall not exceed 0.040 lb/MMBtu-HHV on a 3-hr average basis, as may be monitored via source testing (ARM 17.8.1211, ARM 17.8.752)

D.5. CO emissions from each #2 Crude Unit process heater shall be controlled using good combustion practices. CO emissions from each heater shall not exceed 0.055 lb/MMBtu (ARM 17.8.1211 and ARM 17.8.752).

D.6. Calumet shall comply with the NO_X and CO Umbrella Limitations of Section III.B.5 and III.B.6. The Crude Unit #2 Atmospheric Heater H-2101 and #2 Crude Unit Vacuum Heater H-2102 are affected units (ARM 17.8.1211 and ARM 17.8.749).

D.7. Calumet shall control PM/PM_{10} and $PM_{2.5}$ emissions from the #2 Crude Unit Atmospheric Heater H-2101 and #2 Crude Unit Vacuum Heater H-2102 by utilizing good combustion practices and only combusting low sulfur fuels. Particulate emissions shall not exceed the following (ARM 17.8.1211 and ARM 17.8.752):

a. PM/PM_{10} emissions from each heater shall not exceed 0.00051 lb/MMBtu; and
b. $PM_{2.5}$ emissions from each heater shall not exceed 0.00042 lb/MMBtu

D.8. Calumet shall control CO_2e emissions from each #2 Crude Unit process using low carbon fuels, good combustion practices, and an energy efficient design. The CO_2e emissions shall not exceed 142 lb/MMBtu (ARM 17.8.1211 and ARM 17.8.752).

D.9. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart Ja – Standards of Performance for Petroleum Refineries for which construction, reconstruction, or modification commenced after May 14, 2007, including as applicable to the #2 Crude Unit Atmospheric Heater H-2101 and the #2 Crude Unit Vacuum Heater H-2102 fuel gas combustion devices (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja). As a fuel gas combustion device with a rated heat input greater than 40 MMBtu/hr, the H-2101 is subject to the natural draft NO_X standards of 40 CFR 60 Subpart Ja.

D.10. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, including as applicable to the #2 Crude Unit Atmospheric Heater H-2101 and the #2 Crude Unit Vacuum Heater H-2102, "gas category 1" process heaters (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

D.11. Calumet shall comply with all applicable requirements of 40 CFR 63, Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, including compliance with equipment leak standards and referenced requirements in 40 CFR 60, Subpart VVa – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for equipment in the #2 Crude Unit, and

miscellaneous process vents within the #2 Crude Unit (ARM 17.8.1211, ARM 17.8.302, ARM 17.8.342, and 40 CFR 63 Subpart CC).

D.12. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries and referenced requirements of 40 CFR 60 Subpart VVa (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGGa).

D.13. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ – Standards of Performance from Petroleum Refinery Wastewater Systems, including as applicable to the individual drain system of Crude Unit #2 (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, 40 CFR 60 Subpart QQQ).

D.14. Calumet shall comply with all applicable requirements of 40 CFR 61 Subpart FF – National Emissions Standard for Benzene Waste Operations, as applicable to the drain system of the #2 Crude Unit (ARM 17.8.1211, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Compliance Demonstration

D.15. Calumet shall maintain on-site, manufacturer/vendor supplied specification sheets demonstrating maximum rated design capacity of the H-2101 and H-2102 heaters. Further, Calumet shall track Btu burned in each unit, as already accomplished for NO_X and CO Umbrella limit emissions tracking, emissions inventory purposes, and 40 CFR 60 Subpart Ja compliance (ARM 17.8.1213).

D.16. Calumet shall operate NO_X CEMS and monitor fuel usage and Btu value of fuel in a manner equivalent to 40 CFR 60 Subpart A and Ja requirements, to monitor NO_X emissions on a lb/MMBtu 30-day rolling average basis on the Crude #2 Atmospheric Heater H-2101. Calumet shall maintain records demonstrating 30-day rolling averages on a daily basis, with summary of monitored exceedances versus the 0.035 lb/MMBtu limit of Section III.D.3. Calumet shall use the same data to determine monthly mass emissions of NO_X for NO_X umbrella limit compliance monitoring (ARM 17.8.1213).

D.17. Once every calendar year, Calumet shall test Crude #2 Vacuum Heater H-2102 for NO_X emissions utilizing Method 7E. Fuel usage during the test and fuel analysis taken from fuel used during the test shall be determined to report an average lb/MMBtu value. The lb/MMBtu value shall be used to monitor compliance with the limitation of Section III.D.4 and as the emissions factor for use in determining mass emissions of NO_X for Umbrella limit recordkeeping (ARM 17.8.1213).

D.18. Calumet shall conduct CO testing on the Crude Unit #2 Atmospheric Heater H-2101 and Crude Unit #2 Vacuum Heater H-2102 concurrent with NO_X RATA testing, to monitor compliance with the CO emissions limitation of Section III.D.5. Calumet shall utilize fuel usage and fuel Btu content determined in accord to Section III.D.16 for determining the lb/MMBtu emissions, as well as to track ongoing Btu fired for purposes of determining monthly mass emissions of CO for CO umbrella limit compliance monitoring (ARM 17.8.1213).

D.19. During the next refinery turnaround or as opportunity may provide, Calumet shall make any modifications as may be required to ensure that H-2101 and H-2102 is equipped with appropriate sampling ports such that Method 201A and Method 202 testing could be accomplished if requested. As required by DEQ and Section III.A.1, Calumet shall test the H-2101 and/or H-2102 for PM_{10} and $PM_{2.5}$ utilizing Methods 201A and 202 (ARM 17.8.105 and ARM 17.8.1213).

D.20. Calumet shall monitor compliance with the CO_2e emissions limitations of Section III.D.8 by tracking fuel usage and utilizing established emissions factors as used for greenhouse gas emissions reporting. (ARM 17.8.1213 and ARM 17.8.105).

D.21. Calumet shall monitor compliance with 40 CFR 60 Subpart Ja as required by 40 CFR 60 Subpart Ja (ARM 17.8.1213, ARM 17.8.302, ARM 17.8.340, and 40 CFR 60 Subpart Ja).

D.22. Calumet shall monitor compliance with 40 CFR 63 Subpart DDDDD as required by 40 CFR 63 Subpart DDDDD (ARM 17.8.1213, ARM 17.8.302, ARM 17.8.342, and 40 CFR 63 Subpart DDDDD).

D.23. Calumet shall monitor compliance with 40 CFR 63 Subpart CC as required by 40 CFR 63 Subpart CC (ARM 17.8.1213, ARM 17.8.302, ARM 17.8.342, and 40 CFR 63 Subpart CC).

D.24. Calumet shall monitor compliance with 40 CFR 60 Subpart GGGa as required by 40 CFR 60 Subpart GGGa (ARM 17.8.1213, ARM 17.8.302, ARM 17.8.340, and 40 CFR 60 Subpart GGGa).

D.25. Calumet shall monitor compliance with 40 CFR 60 Subpart QQQ as required by 40 CFR 60 Subpart QQQ (ARM 17.8.1213, ARM 17.8.302, ARM 17.8.340, and 40 CFR 60 Subpart QQQ).

D.26. Calumet shall monitor compliance with 40 CFR 61 Subpart FF as required by 40 CFR 61 subpart FF (ARM 17.8.1213, ARM 17.8.302, ARM 17.8.341, and 40 CFR 61 Subpart FF).

Recordkeeping

D.27. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and must be submitted to DEQ upon request (ARM 17.8.1212).

D.28. Calumet shall maintain records of daily 30-day rolling average emissions of NO_X from the H-2101 as determined via CEMS operated in accord with 40 CFR 60 Subpart A and Ja requirements (ARM 17.8.1212).

D.29. Calumet shall maintain on-site, manufacturer/vendor supplied specification sheets demonstrating maximum rated design capacity of the H-2101 and H-2102 heaters (ARM 17.8.1212, ARM 17.8.1213).

D.30. Calumet shall comply with the NO_X and CO Umbrella limit related recordkeeping requirements of Section III.B.17 for the H-2101 and H-2102 heaters (ARM 17.8.1212).

D.31. Calumet shall keep record of the date that each of the H-2101 and H-2102 heaters are properly equipped to provide for Method 201A and Method 202 testing (ARM 17.8.1212).

D.32. Calumet shall comply with the applicable recordkeeping requirements of 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

D.33. Calumet shall comply with the applicable recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, 40 CFR 63 Subpart DDDDD).

D.34. Calumet shall comply with the applicable recordkeeping requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, 40 CFR 63 Subpart CC).

D.35. Calumet shall comply with the applicable recordkeeping requirements of 40 CFR 60 Subpart GGGa (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGGa).

D.36. Calumet shall comply with the applicable recordkeeping requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

D.37. Calumet shall comply with the applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Reporting

D.38. Calumet shall comply with the NO_X and CO Umbrella limit reporting requirements of Section III.B.26B.24 (ARM 17.8.1212).

D.39. Calumet shall comply with the applicable reporting requirements of 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.302, ARM 17.8.340, and 40 CFR 60 Subpart Ja).

D.40. Calumet shall comply with the applicable reporting requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, 40 CFR 63 Subpart DDDDD).

D.41. Calumet shall comply with the applicable reporting requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, 40 CFR 63 Subpart CC).

D.42. Calumet shall comply with the applicable reporting requirements of 40 CFR 60 Subpart GGGa (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGGa).

D.43. Calumet shall comply with the applicable reporting requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

D.44. Calumet shall comply with the applicable reporting requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

D.45. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1213).

D.46. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. A copy of manufacturer/vendor supplied specification sheets or note as to the date it was submitted and that no changes have taken place.

b. A summary of the of any source testing that was performed during the reporting period including date testing was performed, result of the test, and date the report was submitted or estimated to be submitted;

c. Summary of daily 30-day rolling average NO_X emissions as determined from the H-2101 NO_X CEMS.

d. Summary of CO_2e emissions records of Section III.D.20;

e. Summary demonstrating compliance status with 40 CFR 60 Subpart Ja including reference to submittal dates of reports made or included;

f. Summary demonstrating compliance status with 40 CFR 63 Subpart DDDDD including reference to submittal dates of reports made or included;

g. Summary demonstrating compliance status with 40 CFR 63 Subpart CC including reference to submittal dates of reports made or included;

h. Summary demonstrating compliance status with 40 CFR 60 Subpart GGGa including reference to submittal dates of reports made or included;

i. Summary demonstrating compliance status with 40 CFR 60 Subpart QQQ including reference to submittal dates of reports made or included;

j. Summary demonstrating compliance status with 40 CFR 61 Subpart FF including reference to submittal dates of reports made or included.

E. EU04 - CATALYTIC POLYMERIZATION UNIT

EU04a – Equipment Components
EU04b – Individual Drain System

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
E.1, E.4, E.7, E.10, E.11	HAPs from equipment leaks: 40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
E.2, E.5, E.8, E.10, E.11	VOC from wastewater systems	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	Semiannual and 40 CFR 60 Subpart QQQ

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
E.3, E.6, E.9, E.10, E.11	Benzene emissions from wastewater	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	Semiannual and 40 CFR 61 Subpart FF

Conditions

E.1. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, including compliance with referenced requirements in 40 CFR 60 Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry as applicable to the Catalytic Polymerization Unit. (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

E.2. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ, including as applicable to the individual drain system of the Catalytic Polymerization Unit (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

E.3. Calumet shall comply with all applicable requirements of 40 CFR 61 Subpart FF – National Emission Standard for Benzene Waste Operations as applicable to the drain system of the catalytic polymerization unit (ARM 17.8.1211, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF). Further, Calumet shall comply with applicable requirements of 40 CFR 63 Subpart CC wastewater provisions (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

Compliance Demonstration

E.4. Calumet shall comply with all the applicable requirements in 40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, including compliance with specific requirements in 40 CFR 60 Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry, as specified in each applicable emitting unit (ARM 17.8.749, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63, Subpart CC).

E.5. Calumet shall monitor compliance with 40 CFR 60 Subpart QQQ as required by 40 CFR 60 Subpart QQQ (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

E.6. Calumet shall monitor compliance with 40 CFR 61 Subpart FF as required by 40 CFR 61 Subpart FF (ARM 17.8.1213, ARM 17.8.341, ARM 17.8.302, 40 CFR 61 Subpart FF).

Recordkeeping

E.7. Calumet shall comply with all the applicable recordkeeping requirements in 40 CFR 63 Subpart CC including referenced requirements of 40 CFR 60 Subpart VV (ARM 17.8.340, ARM 17.8.342, ARM 17.8.302, 40 CFR 63, Subpart CC and 40 CFR 60, Subpart VV).

E.8. Calumet shall comply with the applicable recordkeeping requirements for 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

E.9. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Reporting

E.10. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements.

E.11. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. A summary of the of any source testing that was performed during the reporting period including date testing was performed, result of the test, and date the report was submitted or estimated to be submitted;

b. Summary demonstrating compliance status with 40 CFR 63 Subpart CC including reference to submittal dates of reports made or included;

c. Summary demonstrating compliance status with 40 CFR 60 Subpart QQQ including reference to submittal dates of reports made or included;

d. Summary demonstrating compliance status with 40 CFR 61 Subpart FF including reference to submittal dates of reports made and reference to status with regard to the wastewater provisions of 40 CFR 63 Subpart CC.

F. EU05 – FLUID CATALYTIC CRACKING UNIT (FCCU)

EU05a – FCCU Catalyst Regenerator
EU05b – FCCU Preheater H-0302
EU05c – Equipment Components
EU05d – Individual Drain System
EU05e – Electric Driven Compressor C-032701 in Wet Gas Service

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
F.1, A.24, F.19, F.31, F.32, F.40, F.47, F.48	NSPS J for CO on Catalyst Regenerator	CO: 500 ppmvd at stack oxygen	CO: CEMS	Continuous	Quarterly
F.1, A.24, F.18, F.31, F.32, F.40, F.47, F.48	NSPS J for SO_2 on Catalyst Regenerator	SO_2: 50 ppmvd, or 90% reduction or 20 lb/ton coke burn-off or process fresh feed with sulfur content no greater than 0.30% by weight, any of which is determined daily on a 7-day rolling average basis	SO_2: CEMS monitoring 50 ppmvd option	Continuous	Quarterly
F.2, F.3, A.24, F.18, F.31, F.32, F.47, F.48	Consent Decree: SO_2 from Catalyst Regenerator	SO_2: 50 ppmvd @ 0% O_2, 7-day rolling average basis, excluding startup, shutdown, and malfunction. SO_2: 25 ppmvd corrected to 0% O_2, on a 365-day rolling average basis, applicable at all times.	SO_2 and O_2 CEMS	Continuous	Quarterly

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
F.4, F.19, F.31, F.32, F.40, F.47, F.48	Consent Decree: CO from Catalyst Regenerator	500 ppmvd @ 0% O_2, 1-hr avg 500 ppmvd at stack O_2, 100 ppmvd @ 0% O_2, 365-day average	CO CEMS	Continuous	Quarterly
F.5, F.6, F.20, F.31, F.47, F.48	Consent Decree NO_X from Catalyst Regenerator	68 ppmvd at 0% O_2 on a 365-day rolling average basis, applicable at all times 87.0 ppmvd @ 0% O_2 on a 7-day rolling average basis, excluding startup, shutdown, malfunction, and hydrotreater outages	NO_X and O_2 CEMS. For hours in which the FCCU is not in operation, no NO_X value shall be used in the average, and those periods shall be skipped in determining 7-day and 365-day averages.	Ongoing	Quarterly
F.7, F.21, F.31, F.39, F.47, F.49	Consent Decree FCCU PM	15.0 lb/hr	Method 5	Annually	Section III.A.2 and Quarterly
F.8, F.22, F.23, F.31, F.33, F.39, F.45, F.47, F.49	MACT UUU Metal HAPs from catalyst regenerator	40 CFR 63 Subpart UUU	40 CFR 63 Subpart UUU: Opacity CMS and performance testing	Ongoing, performance testing once every 5 years	40 CFR 63 Subpart UUU and Semiannual and Section III.A.2
F.8, F.22, F.23, F.31, F.33, F.45, F.47, F.49	MACT UUU Organic HAPs from catalyst regenerator	40 CFR 63 Subpart UUU: CO limit of 500 ppmvd as an NSPS J affected unit, option to maintain O_2 above 1% by volume during Startup, Shutdown, and Hot Standby	CO CEMS monitoring ppmvd	Continuous	Semiannual

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
F.9, F.22, F.31, F.47, F.49	FCCU Opacity	40%	COMS	Continuous	Semiannual
F.10, A.24, F.24, F.31, F.32, F.40, F.41, F.47, F.48	NSPS J H_2S/SO_2 for fuel gas combustion devices: H-0302 FCCU Preheater	40 CFR 60 Subpart J: 0.10 gr/dscf H_2S in fuel gas, rolling 3-hr average basis	Fuel Gas H_2S content CMS in compliance with NSPS J or Ja	Continuous	Quarterly
F.11, F.25, F.31, F.34, F.44, F.47, F.49	MACT DDDDD: HAPs from FCCU Preheater H-0302 process heaters	40 CFR 63 Subpart DDDDD: Work Practice Standards: Periodic Tune-ups	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	Semiannual and 40 CFR 63 Subpart DDDDD
F.12, F.26, F.31, F.47, F.48	Prohibition on Fuel Oil (except torch oil in FCCU startup)	No Fuel Oil Combustion	Recordkeeping	Ongoing	Quarterly
F.13, F.28, F.31, F.35, F.41 F.47, F.49	NSPS GGG: VOC from Compressor C-032701	NSPS VV	NSPS VV	NSPS VV	Semiannual and 40 CFR 60 Subpart GGG/VV
F.13, F.28, F.31, F.35F.34, F.41, F.47, F.49	NSPS GGG: VOC from equipment components: Pumps, valves, flanges/connectors, etc.	NSPS VV	NSPS VV	NSPS VV	Semiannual and 40 CFR 60 Subpart GGG/VV
F.14, F.27, F.31, F.36, F.46, F.47, F.49	MACT CC – Leaks from equipment in HAP service and Emissions of HAP from pressure relief devices	NSPS VV (or VVa if elected) and MACT CC	NSPS VV (or VVa if elected) and MACT CC	NSPS VV (or VVa if elected) and MACT CC	Semiannual and 40 CFR 60 Subpart VV (or VVa if elected) and 40 CFR 63 Subpart CC
F.15, F.27, F.31, F.36, F.46, F.47, F.49	MACT CC – Miscellaneous Process Vent emissions	MACT CC	MACT CC	MACT CC	Semiannual and 40 CFR 63 Subpart CC
F.16, F.29, F.31, F.37, F.42, F.47, F.49	NSPS QQQ – Individual Drain System VOC emissions	NSPS QQQ	NSPS QQQ	NSPS QQQ	Semiannual and 40 CFR 60 Subpart QQQ
F.17, F.30, F.31, F.38, F.43, F.47, F.49	NESHAP FF – benzene emissions from wastewater	NESHAP FF	NESHAP FF	NESHAP FF	Semiannual and 40 CFR 61 Subpart FF

Conditions

F.1. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart J, as it applies to the FCCU Catalyst Regenerator, for SO_2 and CO (ARM 17.8.1211, Consent Decree Paragraph 15, and 40 CFR 60 Subpart J).

F.2. Calumet shall comply with the FCCU Catalyst Regenerator SO_2 limitation of the Consent Decree, of 50 parts per million, volume dry basis (ppmvd), corrected to 0% O_2, on a 7-day rolling average basis, except for periods of hydrotreater outages (ARM 17.8.1211, Consent Decree Paragraph 12, March 22, 2006 letter from EPA to Calumet).

F.3. SO_2 emissions from the FCCU Catalyst Regenerator shall not exceed 25 ppmvd, corrected to 0% O_2, on a 365-day rolling average basis, applicable at all times (ARM 17.8.1211, Consent Decree Paragraph 12, March 22, 2006 letter from EPA to Calumet).

F.4. CO emissions from the FCCU Catalyst Regenerator shall not exceed 500 ppmvd, corrected to 0% oxygen (O_2) on a 1-hour average basis; 500 ppmvd, at stack oxygen; and 100 ppmvd, corrected to 0% O_2 on a 365-day rolling average basis (ARM 17.8.1211, Consent Decree Paragraph 14, 40 CFR 60 Subpart J, and 40 CFR 63 Subpart UUU).

F.5. NO_X emissions from the FCCU Catalyst Regenerator shall not exceed 68 ppmvd @ 0% O_2 on a 365-day rolling average basis, corrected to 0% oxygen, applicable at all times (ARM 17.8.1211, Consent Decree Paragraph 11, and September 23, 2010 letter from EPA to Calumet).

F.6. NO_x emissions from the FCCU shall not exceed 87 ppmvd, corrected to 0% O_2, on a 7-day rolling average, except for periods of startup, shutdown, malfunction or hydrotreater outages (ARM 17.8.1211, Consent Decree Paragraph 11, and September 23, 2010 letter from EPA to Calumet).

F.7. The FCCU shall be limited to 15.0 lb/hr of PM (ARM 17.8.1211 and Consent Decree Paragraph 13).

F.8. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart UUU – National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, including as applicable to the fluid catalytic cracking unit (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart UUU).

F.9. Calumet shall not discharge from the FCCU Catalyst Regenerator emissions into the atmosphere that exhibit an opacity of 40% or greater averaged over six consecutive minutes (ARM 17.8.304).

F.10. Calumet shall comply with 40 CFR 60 Subpart J as applicable to fuel gas combustion devices for the FCCU Preheater H-0302 (ARM 17.8.1211, Consent Decree Paragraph 17.B, and 40 CFR 60 Subpart J).

F.11. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, including as applicable to the FCCU Pre-heater, a "gas category 1" process heater (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

F.12. Calumet shall not combust fuel oil in any combustion unit, except torch oil may be used in the FCCU Regenerator during FCCU startups (ARM 17.8.1211 and Consent Decree Paragraph 17.C.ii).

F.13. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, including as applicable to the C-032701 compressor in Wet Gas service (ARM 17.8.302, ARM 17.8.340, and 40 CFR 60 Subpart GGG).

F.14. Calumet shall comply with all the applicable requirements in 40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, including compliance with referenced requirements in 40 CFR 60 Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

F.15. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries for miscellaneous process vents within the FCCU (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

F.16. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ – Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems, including as applicable to the individual drain system of the FCCU (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, 40 CFR 60 Subpart QQQ).

F.17. Calumet shall comply with all applicable requirements of 40 CFR 61 Subpart FF – National Emissions Standard for Benzene Waste Operations, as applicable to the drain system of the FCCU (ARM 17.8.1211, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Compliance Demonstration

F.18. Calumet shall monitor compliance with SO_2 emissions limitations of the Consent Decree and 40 CFR 60 Subpart J for the FCCU by continuously monitoring SO_2 emissions utilizing CEMS in compliance with 40 CFR 60 Subpart J, 40 CFR §§ 60.11, 60.13 and Part 60 Appendix A, and the applicable performance specification requirements of 40 CFR Part 60 Appendices B and F. Data summarized by averaging periods shall be available upon request (ARM 17.8.1212, Consent Decree Paragraphs 12.A and 12.D, 40 CFR 60 Subpart J, and ARM 17.8.1213).

F.19. Calumet shall monitor compliance with CO emissions limitations of 40 CFR 60 Subpart J utilizing CEMS in compliance with 40 CFR §§ 60.11, 60.13 and Part 60 Appendix A, and the applicable performance specification test of 40 CFR Part 60 Appendices B and F. Data summarized by averaging periods shall be available upon request (ARM 17.8.1212, Consent Decree Paragraph 14.C, ARM 17.8.1213).

F.20. Calumet shall continuously monitor NO_X (and O_2) emissions from the FCCU Catalyst Regenerator utilizing CEMS in accordance with 40 CFR §§ 60.11, 60.13, and Part 60 Appendix A, and the applicable performance requirements of 40 CFR Part 60 Appendices B and F. For hours 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. Data summarized by averaging periods shall be available upon request (ARM 17.8.1212, ARM 17.8.1213, Consent Decree Paragraph 11.F, September 23, 2010 letter from EPA to Calumet).

F.21. Compliance with the PM emission limit of 15.0 lb/hr shall be monitored by conducting a 3-hour performance test representative of normal operating conditions for PM emissions by December 31 of each calendar year. If any performance test undertaken pursuant this section is not representative of normal operating conditions, Calumet shall conduct a subsequent performance test representative of normal operating conditions by no later than 90 days after the test that was not representative (ARM 17.8.1212, Consent Decree Paragraph 15, ARM 17.8.1213).

F.22. Calumet shall install and use a COMS to continuously monitor opacity of the FCCU Catalyst Regenerator emissions to monitor compliance with the 40% opacity rule of ARM 17.8.304 as well as monitor compliance with the nickel limit in 40 CFR 63 Subpart UUU. Calumet shall install, certify, calibrate, maintain and operate the COMS in accordance with the requirements of 40 CFR 63 Subpart UUU, including 40 CFR 63.8 and including maintaining records to monitor conformance with procedures in Calumet's Operations, Maintenance, and Monitoring Plan (OMMP) (ARM 17.8.1212, ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart UUU).

F.23. Calumet shall monitor compliance with 40 CFR 63 Subpart CC as required by 40 CFR 63 Subpart CC (ARM 17.8.342 and 40 CFR 63 Subpart CC).

F.24. Calumet shall continuously monitor the H_2S content of fuel gas burned in the FCCU Preheater H-0302 in accord with 40 CFR 60 Subpart J. Calumet shall install, certify, calibrate, maintain, and operate a fuel gas CEMS in accordance with the requirements of 40 CFR §§ 60.11, 60.13, and Part 60 Appendix A, and the applicable performance requirements of 40 CFR Part 60 Appendices B and F. Data summarized by averaging periods shall be available upon request (ARM 17.8.1212, ARM 17.8.1213, Consent Decree Paragraph 17.B).

F.25. Calumet shall monitor compliance with 40 CFR 63 Subpart DDDDD as required by 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

F.26. Calumet shall record, in a log, any time that torch oil is burned in the FCCU Regenerator. Such log shall include the date, timeframe, and operational status of the FCCU during such timeframe (ARM 17.8.1212, ARM 17.8.1213).

F.27. Calumet shall monitor compliance with 40 CFR 63 Subpart CC as required by 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.1213, ARM 17.8.340, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

F.28. Calumet shall monitor compliance with 40 CFR 60 Subpart GGG as required by 40 CFR 60 Subpart GGG (ARM 17.8.1212, ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGG).

F.29. Calumet shall monitor compliance with 40 CFR 60 Subpart QQQ as required by 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

F.30. Calumet shall monitor compliance with 40 CFR 61 Subpart FF as required by 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.1213, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Recordkeeping

F.31. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and must be submitted to DEQ upon request (ARM 17.8.1212).

F.32. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart J (ARM 17.8.1212, Consent Decree Paragraph 15 and Paragraph 17, 40 CFR 60 Subpart J).

F.33. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart UUU (ARM 17.8.1212, ARM 17.8.342, ARM and 40 CFR 63, Subpart UUU).

F.34. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

F.35. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart GGG (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGG).

F.36. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

F.37. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

F.38. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Reporting

F.39. Any compliance source test reports must be submitted in accordance with Section III.A.2 (ARM 17.8.106 and ARM 17.8.1212).

F.40. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302 and 40 CFR 60 Subpart J).

F.41. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart GGG (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302 and 40 CFR 60 Subpart GGG).

F.42. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302 and 40 CFR 60 Subpart QQQ).

F.43. Calumet shall comply with all applicable reporting requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

F.44. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

F.45. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart UUU (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart UUU).

F.46. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

F.47. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements.

F.48. Within 45 days of the end of each calendar quarter, Calumet shall provide the following for that calendar quarter period (ARM 17.8.1212):

a. For each CEMS/CMS unit required by the Consent Decree:

i. Excess Emissions and Monitoring System Performance Reports and Data Assessment Reports

ii. For any quarter with excess emissions greater than 1% of the total operating time of the affected source during the reporting period, or any quarter with monitoring downtime greater than 5% of the total operating time of the affected source during the reporting period, detailed emissions data or if no data available, estimated emissions, during that time.

b. Summary of the fuel oil usage log required by Section III.F.26

c. Enhanced LDAR reporting requirements of the Consent Decree

F.49. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. Summary demonstrating compliance with 40 CFR 63 Subpart UUU including clearly indicating the compliance monitoring options utilized during the reporting period and summary of underlying data, including CEMS and COMS performance and excess emissions information determined on a quarterly basis;

b. Summary demonstrating compliance status with 40 CFR 63 Subpart DDDDD including reference to submittal dates of reports made or included;

c. Summary demonstrating compliance status with the 40% opacity requirement;
d. Summary demonstrating compliance status with 40 CFR 63 Subpart CC, organized by applicable sections of Subpart CC, including reference to submittal dates of reports made or included;

e. Summary demonstrating compliance with 40 CFR 60 Subpart GGG, including reference to submittal dates of reports made or included;

f. Summary of compliance with 40 CFR 61 Subpart FF including reference to submittal dates of reports made or included;

g. A summary of the of any source testing that was performed during the reporting period including date testing was performed, result of the test, and date the report was submitted or estimated to be submitted;

h. Reference to quarterly reports required by the consent decree.

G. EU06 – CATALYTIC REFORMER UNIT and NAPHTHA HYDROTREATING UNIT

EU06a Reformer Heater H-0403
EU06b Reformer Unit, Process Vents
EU06c Reformer Unit, Individual Drain System
EU06d Catalytic Reformer Electric Driven Compressor C-040307 in H_2 Service
EU06e Naphtha Splitter Reboiler H-0405
EU06f Naphtha HDS Heater H-0402a
EU06g Diesel/Gas Oil HTU Electric Driven Compressor C-172801

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
G.1, G.10, G.19, G.20, G.30, G.39, G.40	Catalytic Reformer Unit - Organic & Inorganic HAPs from process vents	40 CFR 63 Subpart UUU	40 CFR 63, Subpart UUU	Ongoing	40 CFR 63 Subpart UUU and Semiannual
			OMMP Plan	Ongoing	Semiannual
G.2, G.11, G.19, G.21, G.31, G.39, G.40	Naptha HDS unit Heater H-0402a, Naptha Splitter Reboiler Heater H-0405 SO_2	40 CFR 60 Subpart Ja	40 CFR 60, Subpart Ja Fuel Gas H_2S CEMS	Continuous	Semiannual and 40 CFR 60 Subpart Ja
G.3, G.12, G.19, G.22, G.32, G.39, G.40	Catalytic Reformer Heater H-0403 SO_2	40 CFR 60 Subpart J	40 CFR 60 Subpart J Fuel Gas H_2S CEMS	Continuous	Semiannual and 40 CFR 60 Subpart J
G.4, G.13, G.19, G.23, G.33, G.39, G.40	Naptha HDS unit Heater H-0402a, Naptha Splitter Reboiler Heater	40 CFR 63 Subpart DDDDD:	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	Semiannual and 40 CFR 63 Subpart DDDDD

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
	H-0405, Catalytic Reformer Heater H-0403 HAPs	Work Practice Standards: Periodic Tune-ups			
G.5, G.14, G.19, G.24, G.34, G.39, G.40	VOC and HAP Equipment Leaks from Catalytic Reformer Group I Process Vents	40 CFR 63 Subpart CC	40 CFR 63, Subpart CC	40 CFR 63, Subpart CC	Semiannual and 40 CFR 63 Subpart CC
	VOC and HAP Equipment Leaks for Catalytic Reformer Components	40 CFR 63 Subpart CC	40 CFR 60 Subpart VV	40 CFR 60 Subpart VV	Semiannual and 40 CFR 63 Subpart CC
	HAP from Wastewater	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
	VOC and HAP Equipment Leaks from Naptha Unit components	40 CFR 63 Subpart CC	40 CFR 60 Subpart VVa	40 CFR 60 Subpart VVa	Semiannual and 40 CFR 63 Subpart CC
G.6, G.19, G.25, G.35, G.39, G.40	VOC from HTU Equipment Components	40 CFR 60 Subpart GGG	40 CFR 60 Subpart VV	40 CFR 60 Subpart VV	Semiannual and 40 CFR 60 Subpart GGG
G.7, G.16, G.19, G.26, G.36, G.39, G.40	VOC from Naphtha Unit Equipment Components	40 CFR 60 Subpart GGGa	40 CFR 60 Subpart VVa	40 CFR 60 Subpart VVa	Semiannual and 40 CFR 60 Subpart GGGa
G.8, G.17, G.19, G.27, G.37, G.39, G.40	VOC from Wastewater – Individual drain system	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	Semiannual and 40 CFR 60 Subpart QQQ
G.9, G.18, G.19, G.38, G.39, G.40	HAP from Wastewater – Individual Drain System	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	Semiannual and 40 CFR 61 Subpart FF

Conditions

G.1. Calumet shall comply with 40 CFR 63 Subpart UUU – National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart UUU).

G.2. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart Ja – Standards of Performance for Petroleum Refineries for which construction, reconstruction, or modification commenced after May 14, 2007, including as applicable to the Naphtha Splitter Reboiler H-0405 and Naphtha HDS Heater H-0402a (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

G.3. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart J – Standards of Performance for Petroleum Refineries, including as applicable to the Catalytic Reformer Heater H-0403 (ARM 17.8.1211, Consent Decree Paragraph 15).

G.4. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, including as applicable to the Catalytic Reformer Heater H-0403, Naphtha Splitter Reboiler Heater H-0405 and Naphtha HDS Heater H-0402a, "gas category 1" process heaters (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

G.5. Calumet shall comply with all the applicable requirements in 40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, including miscellaneous process vents, HAPs from wastewater, and referenced requirements in 40 CFR 60 Subpart VV and VVa – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

G.6. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries and referenced requirements of 40 CFR 60 Subpart VV, including as applicable to the C-172801 Compressor (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGG).

G.7. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries and referenced requirements of 40 CFR 60 Subpart VVa, including as applicable to the Naphtha Hydrotreating Unit and Compressor C-040307. Calumet shall present to DEQ an engineering analysis if these compressors are believed to be in Hydrogen Service (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGGa).

G.8. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ, including as applicable to the individual drain system of the Catalytic Reformer Unit (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, 40 CFR 60 Subpart QQQ).

G.9. Calumet shall comply with all applicable requirements of 40 CFR 61 Subpart FF – National Emissions Standard for Benzene Waste Operations, as applicable to the drain system of the Catalytic Reformer Unit (ARM 17.8.1211, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Compliance Demonstration

G.10. Calumet shall monitor compliance with 40 CFR 63 Subpart UUU as required by 40 CFR 63 Subpart UUU, including maintaining records to document conformance with procedures in Calumet's required OMMP (ARM 17.8.1212, ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63, Subpart UUU).

G.11. Calumet shall monitor compliance with 40 CFR 60 Subpart Ja as required by 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

G.12. Calumet shall monitor compliance with 40 CFR 60 Subpart J as required by 40 CFR 60 Subpart J (ARM 17.8.1212, ARM, 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart J).

G.13. Calumet shall monitor compliance with 40 CFR 63 Subpart DDDDD as required by 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

G.14. Calumet shall monitor compliance with 40 CFR 63 Subpart CC as required by 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

G.15. Calumet shall monitor compliance with 40 CFR 60 Subpart GGG as required by 40 CFR 60 Subpart GGG (ARM 17.8.1212, ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGG).

G.16. Calumet shall monitor compliance with 40 CFR 60 Subpart GGGa as required by 40 CFR 60 Subpart GGGa (ARM 17.8.1212, ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGGa).

G.17. Calumet shall monitor compliance with 40 CFR 60 Subpart QQQ as required by 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

G.18. Calumet shall monitor compliance with 40 CFR 61 Subpart FF as required by 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.1213, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Recordkeeping

G.19. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and must be submitted to DEQ upon request (ARM 17.8.1212).

G.20. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart UUU (ARM 17.8.1212, ARM 17.8.342, ARM and 40 CFR 63, Subpart UUU).

G.21. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

G.22. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart J (ARM 17.8.1212, Consent Decree Paragraph 15 and Paragraph 17, 40 CFR 60 Subpart J).

G.23. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302 and 40 CFR 63, Subpart DDDDD).

G.24. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302 and 40 CFR 63 Subpart CC).

G.25. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart GGG (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGG).

G.26. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart GGGa (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 63 Subpart GGGa).

G.27. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63, Subpart QQQ).

G.28. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Reporting

G.29. Any compliance source test reports must be submitted in accordance with Section III.A.2 (ARM 17.8.106 and ARM 17.8.1212).

G.30. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart UUU (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart UUU).

G.31. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302 and 40 CFR 60 Subpart Ja).

G.32. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302 and 40 CFR 60 Subpart J).

G.33. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

G.34. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302 and 40 CFR 63 Subpart CC).

G.35. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart GGG (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302 and 40 CFR 60 Subpart GGG).

G.36. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart GGGa (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302 and 40 CFR 60 Subpart GGGa).

G.37. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302 and 40 CFR 60 Subpart QQQ).

G.38. Calumet shall comply with all applicable reporting requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

G.39. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements.

G.40. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. A summary of the of any source testing that was performed during the reporting period including date testing was performed, result of the test, and date the report was submitted or estimated to be submitted;

b. Summary demonstrating compliance status with 40 CFR 63 Subpart UUU, including reference to submittal dates of reports made or included;
c. Summary demonstrating compliance status with 40 CFR 60 Subpart Ja including reference to submittal dates of reports made or included;

d. Summary demonstrating compliance status with 40 CFR 60 Subpart J including reference to submittal dates of reports made or included;

e. Summary demonstrating compliance status with 40 CFR 63 Subpart CC including reference to submittal dates of reports made or included;

f. Summary demonstrating compliance status with 40 CFR 60 Subpart GGG including reference to submittal dates of reports made or included;

g. Summary demonstrating compliance status with 40 CFR 60 Subpart GGGa including reference to submittal dates of reports made or included;

h. Summary demonstrating compliance status with 40 CFR 60 Subpart QQQ including reference to submittal dates of reports made or included;

i. Summary demonstrating compliance status with 40 CFR 61 Subpart FF including reference to submittal dates of reports made or included.

H. EU07 – ALKYLATION UNIT

EU07a - Deisobutanizer Reboiler
EU07b - Pressure Vessels in Hydrofluoric Acid Service
EU07c - Equipment Components
EU07d – Individual Drain System

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
H.1, H.8, H.15, H.27, H.28	All HF acid pressure vessels	Vent to flare	Recordkeeping	Ongoing	Semiannual
H.2, H.9, H.15, H.16, H.27, H.28	Alkylation Unit fugitives	Design and operational standards	40 CFR 60.482-2 & 40 CFR 60.482-7, and 40 CFR 60 Subpart QQQ	Pumps: weekly Valves: monthly Other: quarterly	Semiannual

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
H.3, H.10, A.24, H.15, H.17, H.22, H.27, H.28	NSPS J Fuel Gas H_2S Content for Reboiler	NSPS J Fuel Gas H_2S Content: 0.10 gr/dscf	Fuel Gas H_2S CMS	Continuous	Quarterly
H.4, H.11, H.15, H.18, H.23, H.27, H.28	MACT DDDDD: HAPS from Alkylation Unit Process Heater	Work Practice Standards: Periodic Tune-ups	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD and Semiannually
H.5, H.12, H.15, H.24, H.27, H.28	MACT CC – HAPS from equipment leaks	40 CFR 63 Subpart CC	40 CFR 60 Subpart VV	40 CFR 60 Subpart VV	Semiannual and 40 CFR 63 Subpart CC
H.5, H.12, H.15, H.24, H.27, H.28	MACT CC – HAPs from process vents	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
H.5, H.12, H.15, H.19, H.24, H.27, H.28	MACT CC – HAPs from drain system	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
H.6, H.13, H.15, H.20, H.25, H.27, H.28	NSPS QQQ: VOC from drain system	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	Semiannual and 40 CFR 60 Subpart QQQ
H.7, H.14, H.15, H.21, H.26, H.27, H.28	NESHAP FF: Benzene from drain system	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	Semiannual and 40 CFR 61 Subpart FF

Conditions

H.1. All pressure vessels in hydrofluoric acid service, except storage tanks, shall be vented to the flare system (ARM 17.8.1211, ARM 17.8.749, and ARM 17.8.752).

H.2. The hydrofluoric acid alkylation unit shall be operated and maintained as follows (ARM 17.8.749 and ARM 17.8.752):

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

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

c. All pumps used in the alkylation plant shall be fitted with the highest quality state-of-the-art mechanical seals.

d. All pumps shall be monitored and maintained as described in 40 CFR 60.482-2 and all control valves shall be monitored and maintained as described in 40 CFR 60.482-7. All other potential sources of VOC leaks shall be inspected quarterly for evidence of leakage by visual or other detection methods. Repairs shall be made promptly as described in 40

CFR 482-7(d). Records of monitoring and maintenance shall be maintained on site for a minimum of 2 years.

e. All process drains shall consist of water seal traps with covers.

f. All equipment shall be operated and maintained as described in 40 CFR 60.692-2, 60.692-6, and 60.693-1. Inspection reports shall be made available for inspection upon request.

H.3. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart J – Standards of Performance for Petroleum Refineries, including as applicable to the Alkylation Unit Deisobutanizer Reboiler (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, 40 CFR 60 Subpart J, and Consent Decree Paragraph 15). The Alkylation Unit Deisobutanizer Reboiler shall burn only natural gas or fuel gas in compliance with 40 CFR 60 Subpart J (ARM 17.8.749).

H.4. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, including as applicable to the Alkylation Unit Deisobutanizer Reboiler, a "gas category 1" process heater (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

H.5. Calumet shall comply with all the applicable requirements in 40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, including compliance with referenced requirements in 40 CFR 60 Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry, requirements for miscellaneous process vents, and wastewater provisions (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

H.6. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ – Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

H.7. Calumet shall comply with all applicable requirements of 40 CFR 61 Subpart FF – National Emissions Standard for Benzene Waste Operations, as applicable to the individual drain system of the Alkylation Unit (ARM 17.8.1211, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Compliance Demonstration

H.8. Calumet shall maintain a log to document that all pressure vessels in HF acid service are vented to the flare, which shall specifically include the reasons for every case in which an applicable pressure vessel is not vented to the flare (ARM 17.8.1213).

H.9. Compliance with Section III.H.2 for pumps and control valves not subject to 40 CFR 63 Subpart CC shall meet the requirements of 40 CFR 60.482-2 and 40 CFR 60.482-7, respectively, that includes, but is not limited to the following (ARM 17.8.1213):

a. Each pump in light liquid service shall be monitored monthly to determine leaks by methods specified in §60.485;

b. Each pump in light liquid service shall be visually inspected each calendar week for indications of liquids dripping from the pump seal; and

c. Each control valve shall be monitored as per 40 CFR 60.482-7 to detect leaks by the methods specified in §60.485.

H.10. Calumet shall monitor compliance with 40 CFR 60 Subpart J as required by 40 CFR 60 Subpart J (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart J).

H.11. Calumet shall monitor compliance with 40 CFR 63 Subpart DDDDD as required by 40 CFR 63 Subpart DDDDD (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

H.12. Calumet shall monitor compliance with 40 CFR 63 Subpart CC as required by 40 CFR 63 Subpart CC (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

H.13. Calumet shall monitor compliance with 40 CFR 60 Subpart QQQ as required by 40 CFR 60 Subpart QQQ (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

H.14. Calumet shall monitor compliance with 40 CFR 61 Subpart FF as required by 40 CFR 61 Subpart FF (ARM 17.8.1213, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Recordkeeping

H.15. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and must be submitted to DEQ upon request (ARM 17.8.1212).

H.16. Calumet shall maintain records of inspections and repairs made under Section III.H.9 (ARM 17.8.1212).

H.17. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340, ARM 178.8.302, and 40 CFR 60 Subpart J).

H.18. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, AM 17.8.302, and 40 CFR 63 Subpart DDDDD).

H.19. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

H.20. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

H.21. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Reporting

H.22. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302 and 40 CFR 60 Subpart J).

H.23. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302 and 40 CFR 63 Subpart DDDDD).

H.24. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302 and 40 CFR 63 Subpart CC).

H.25. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

H.26. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

H.27. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements.

H.28. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. summary of the HF acid pressure vessel log required by Section III.H.8;
b. summary of the leak detection and repair log required by Section III.H.16;
c. summary demonstrating compliance status with 40 CFR 60 Subpart J including reference to submittal dates of reports made or included;
d. Summary demonstrating compliance status with 40 CFR 63 Subpart DDDDD including reference to submittal dates of reports made or included;
e. summary demonstrating compliance status with 40 CFR 63 Subpart CC including reference to submittal dates of reports made or included;
f. summary demonstrating compliance status with 40 CFR 60 Subpart QQQ including reference to submittal dates of reports made or included;
g. summary demonstrating compliance status with 40 CFR 61 Subpart FF including reference to submittal dates of reports made or included.

I. EU08 – ISOMERIZATION UNIT

EU08a – Equipment Components
EU08b – Individual Drain System

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
I.1, I.5, I.8, I.9, I.12, I.15, I.16	MACT CC – HAPs from equipment leaks	40 CFR 63 Subpart CC	40 CFR 60 Subpart VV	40 CFR 60 Subpart VV	40 CFR 63 Subpart CC and Semiannual
I.2, I.5, I.8, I.9, I.12, I.15, I.16	MACT CC – HAPs from drain system	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC and Semiannual
I.3, I.6, I.8, I.10, I.13, I.15, I.16	NSPS QQQ – VOC from drain system	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ and semiannual
I.4, I.7, I.8, I.11, I.14, I.15, I.16	NESHAP FF – benzene from drain system	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF and semiannual

Conditions

I.1. Calumet shall comply with all the applicable requirements in 40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, including compliance with referenced requirements in 40 CFR 60 Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

I.2. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries for wastewater provisions (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

I.3. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ – Standards of Performance for VOC emissions from Petroleum Refinery Wastewater Systems as applicable to the Isomerization Unit individual drain system (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

I.4. Calumet shall comply with all applicable requirements of 40 CFR 61 Subpart FF – National Emissions Standard for Benzene Waste Operations, as applicable to the drain system of the Isomerization Unit (ARM 17.8.1211, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Compliance Demonstration

I.5. Calumet shall monitor compliance with 40 CFR 63 Subpart CC as required by 40 CFR 63 Subpart CC (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

I.6. Calumet shall monitor compliance with 40 CFR 60 Subpart QQQ as required by 40 CFR 60 Subpart QQQ (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

I.7. Calumet shall monitor compliance with 40 CFR 61 Subpart FF as required by 40 CFR 61 Subpart FF (ARM 17.8.1213, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Recordkeeping

I.8. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and must be submitted to DEQ upon request (ARM 17.8.1212).

I.9. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart CC. (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

I.10. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

I.11. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Reporting

I.12. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302 and 40 CFR 63 Subpart CC).

I.13. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

I.14. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

I.15. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements.

I.16. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. summary demonstrating compliance status with 40 CFR 63 Subpart CC including reference to submittal dates or reports made or included;
b. summary demonstrating compliance status with 40 CFR 60 Subpart QQQ including reference to submittal dates or reports made or included;
c. summary demonstrating compliance status with 40 CFR 61 Subpart FF including reference to submittal dates or reports made or included.

J. EU09 – HYDROGEN PLANTS

EU09a - #1 H_2 Plant Furnace H-1801
EU09b - #1 H_2 Plant Equipment Components
EU09c - #1 H_2 Plant Individual Drain System
EU09d - #2 H_2 Plant Furnace H-2815
EU09e - #2 H_2 Plant Equipment Components
EU09f - #2 H_2 Plant Individual Drain System
EU09g - #3 H_2 Plant Furnace A: H-3815A
EU09h - #3 H_2 Plant Furnace B: H-3815B
EU09i - #3 H_2 Plant Equipment Components
EU09j - #3 H_2 Plant Individual Drain System

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
J.1, J.22, J.34, J.35, J.45, J.54, J.55	NO_X and CO Umbrella Limit: #3 Hydrogen Plant:	Section III.B.5 and III.B.6	NO_X: CEMS CO: Source Test	NO_X: Ongoing CO: Annually	Semiannual and Section III.A.2
J.2, J.19, A.2, J.34, J.54, J.55	#1 H_2 Plant NO_X	0.07 lb/MMBtu 1.90 lb/hr 8.3 TPY	Source test Fuel Tracking	Once/permit term Ongoing	Semiannual and Section III.A.2
J.3, J.19, A.2, J.34, J.54, J.55	#1 H_2 Plant CO	0.93 lb/hr 4.1 TPY	Source Test Fuel Tracking	Once/permit term Ongoing	Semiannual and Section III.A.2
J.4, J.20, J.34, J.54, J.55	H_2 Plant Furnaces Fuel Type	Burn natural gas and recycled hydrogen plant gas only	Recordkeeping	Ongoing	Semiannual
J.5, J.21, J.34, J.54, J.55	#3 H_2 Plant Capacity	67 MMBtu/hr each heater	Recordkeeping	Ongoing	Semiannual
J.6, J.27, J.34, J.37, J.47, J.54, J.55	#2 H_2 Plant Furnace NO_X (BACT and CD)	0.033 lb/MMBtu - HHV	NO_X CEMS	Continuous	Semiannual
J.7, J.22, J.34, J.44, J.54, J.55	#3 H_2 Plant Furnace NO_X (BACT)	0.051 lb/MMBtu, 30-day average	NO_X CEMS	Continuous	Semiannual
J.8, J.23, J.34, J.54, J.55	#3 H_2 Plant CO	0.03 lb/MMBtu 17.6 TPY	Testing once every 5 years concurrent with NO_X RATA	Continuous	Semiannual
J.9, J.24, J.34, J.54, J.55	#3 H_2 Plant CO_2	133,038 TPY	Recordkeeping	Continuous	Semiannual

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
J.10, J.34, J.54, J.55	#3 H_2 Plant PM, PM_{10}, and $PM_{2.5}$	PM/PM_{10}: 0.00051 lb/MMBtu $PM_{2.5}$: 0.00042 lb/MMBtu	Recordkeeping and Method 201a and 202	As required by DEQ and Section III.A.1	Semiannual and Section III.A.2
J.11, A.24, J.26, J.34, J.36, J.46, J.54, J.55	NSPS J: #1 H_2 Plant Furnace SO_2	Burn natural gas and recycled hydrogen plant gas only	40 CFR 60 Subpart J @ 40 CFR 60.105(b)	40 CFR 60 Subpart J	Quarterly and 40 CFR 60 Subpart J
J.12, J.27, J.37, J.47, J.54, J.55	NSPS Ja: #2 and #3 H_2 Plant Furnaces SO_2	Burn natural gas and recycled hydrogen plant gas only	40 CFR 60 Subpart Ja @ 40 CFR 60.107a(b)	40 CFR 60 Subpart Ja	40 CFR 60 Subpart Ja and Semiannual
J.12, J.27, J.37, J.47, J.54, J.55	NSPS Ja: #2 and #3 H_2 Plant Furnaces NO_X	60 ppmvd @ 0% O_2, 30-day rolling average or 0.060 lb/MMBtu-HHV, 30-day rolling average	NO_X CEMS	Continuous	40 CFR 60 Subpart Ja and Semiannual
J.13, J.28, J.34, J.38, J.48, J.54, J.55	MACT DDDDD: HAPs from Hydrogen Plant Furnaces	40 CFR 63 Subpart DDDDD: Work Practice Standards: Periodic Tune-ups	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD and Semiannual
J.14, J.29, J.39, J.49, J.54, J.55	NSPS GGG: #1 H_2 Plant VOC from equipment leaks	40 CFR 60 Subpart GGG	40 CFR 60 Subpart VV	40 CFR 60 Subpart VV	40 CFR 60 Subpart GGG and Semiannual
J.15, J.30, J.34, J.40, J.50, J.54, J.55	NSPS GGGa: #2 and #3 H_2 Plant VOC from equipment leaks	40 CFR 60 Subpart GGGa	40 CFR 60 Subpart VVa	40 CFR 60 Subpart VVa	40 CFR 60 Subpart GGGa and Semiannual
J.16, J.31, J.34, J.41, J.51, J.54, J.55	MACT CC: HAPs from drain systems	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC and Semiannual
J.17, J.32, J.34, J.42, J.52, J.54, J.55	NSPS QQQ: VOC from drain systems	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ and Semiannual

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
J.18, J.33, J.34, J.43, J.53, J.54, J.55	NESHAP FF: Benzene from drain systems	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF and Semiannual

Conditions

J.1. Calumet shall comply with the NO_X and CO Umbrella limits of Section III.B.5 and III.B.6. The #3 Hydrogen Plant H-3815A and B heaters are affected units (ARM 17.8.749, ARM 17.8.1211).

J.2. The #1 Hydrogen Plant furnace shall not exceed NO_X emissions of 0.07 lb/MMBtu, 1.90 lb/hr, and 8.3 tons per year (ARM 17.8.752 and ARM 17.8.1211).

J.3. The #1 Hydrogen Plant furnace shall not exceed CO emissions of 0.93 lb/hr or 4.1 TPY (ARM 17.8.752).

J.4. The Hydrogen Plant furnaces shall only be fired with commercially available natural gas, which may include recycled gas from the hydrogen plants, and shall not be fired with refinery fuel gas or refinery liquified petroleum gas (ARM 17.8.1211 and ARM 17.8.752).

J.5. The #3 Hydrogen Plant furnace must be equipped with ultra-low NO_X burners and the maximum capacity of each of the two heaters shall not exceed 67 MMBtu/hr on a HHV basis (ARM 17.8.752 and ARM 17.8.1211).

J.6. The #2 Hydrogen Plant furnace must be equipped with next-generation ultra-low NO_X burners (ARM 17.8.1211 and ARM 17.8.749). NO_X emissions from the process heater shall not exceed 0.033 lb/MMBtu based on a higher heating value basis (ARM 17.8.752 and ARM 17.8.1211).

J.7. NO_X emissions from each #3 Hydrogen Plant heater shall not exceed 0.051 lb/MMBtu based on a 30-day rolling average (ARM 17.8.752 and ARM 17.8.1211).

J.8. CO emissions from each #3 Hydrogen Plant heater shall not exceed 0.03 lb/MMBtu or 17.6 tons per year based on a 12-month rolling average (ARM 17.8.1211 and ARM 17.8.752).

J.9. The combined carbon dioxide equivalent emissions from the #3 Hydrogen Plant heaters shall not exceed 133,038 TPY based on a 12-month rolling average (ARM 17.8.752).

J.10. Calumet shall control PM, PM_{10} and $PM_{2.5}$ emissions from each Hydrogen Plant #3 Reformer Heater (H-31A and H-31B) by utilizing good combustion practices and only combusting low sulfur fuels.

a. PM/PM_{10} emissions shall note exceed 0.00051 lb/MMBtu
b. $PM_{2.5}$ emissions shall not exceed 0.00042 lb/MMBtu

J.11. Calumet shall comply with requirements of 40 CFR 60 Subpart J – Standards of Performance for Petroleum Refineries, as applicable to the #1 Hydrogen Plant Furnace as requirement of the Consent Decree (ARM 17.8.1211 and Consent Decree Paragraph 15).

J.12. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart Ja – Standards of Performance for Petroleum Refineries, including as applicable to the #2 and #3 Hydrogen Plant Furnaces (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

J.13. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, including as applicable to the #1, #2, and #3 Hydrogen Plant Furnaces, "gas category 1" process heaters (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

J.14. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries and referenced requirements of 40 CFR 60 Subpart VV, including as applicable to the #1 Hydrogen Plant (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGG).

J.15. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries and referenced requirements of 40 CFR 60 Subpart VVa, including as applicable to the #2 and #3 Hydrogen Plants (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGGa).

J.16. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart CC as applicable to the drain systems of the hydrogen plants (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 63 Subpart CC).

J.17. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ as applicable to the individual drain systems of each hydrogen plant (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

J.18. Calumet shall comply with all applicable requirements of 40 CFR 61 Subpart FF as applicable to the drain systems of the hydrogen plants (ARM 17.8.1211, ARM 17.8.341, and 40 CFR 61 Subpart FF).

Compliance Demonstration

J.19. Calumet shall test the Hydrogen Plant #1 reformer heater biennially, to monitor compliance with the NO_X and CO limitations of Section III.J.2 and III.J.3 (ARM 17.8.1213) and to determine an emissions factor to monitor compliance with the mass emissions limitations of Section III.J.2 and III.J.3. (ARM 17.8.1213). Monitoring for NO_X and CO mass emission limits shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test (ARM 17.8.1213, ARM 17.8.749). Should the unit be idle at testing deadline, testing shall be conducted as soon as reasonably possible after startup, which shall not be greater than 180 days after startup (ARM 17.8.1213).

J.20. Calumet shall maintain a record of the type(s) of fuel burned in the hydrogen plant furnaces (ARM 17.8.1213).

J.21. Calumet shall maintain on-site, and available upon request, record of the maximum rated capacity of #3 Hydrogen Plant furnaces (ARM 17.8.1213).

J.22. #3 Hydrogen Plant Reformer Heaters H-3815A and H-3815B shall be equipped with NO_X CEMS in compliance with 40 CFR 60 Subpart A and Ja by no later than June 30, 2018 (ARM 17.8.749, ARM 17.8.1213).

J.23. Once during the term of this permit, Calumet shall conduct CO testing to monitor compliance with Section III.J.8. An emissions factor shall be developed from the test to monitor compliance with the TPY emissions limitation of Section III.J.8 (ARM 17.8.1213, ARM 17.8.106).

J.24. By the 25th of each month, Calumet shall calculate and record the monthly and rolling 12-month emissions of CO_2e from the #3 hydrogen plant (ARM 17.8.1213).

J.25. Calumet shall maintain records demonstrating utilization of good combustion practices, and combusting low sulfur fuels. NSPS Ja fuel gas H_2S records may be utilized to monitor low sulfur fuel combustion. As required by DEQ and Section III.A.1, Calumet shall test the H-4101 and H-4102 heaters utilizing Method 201 and 202. During the next refinery turnaround or as opportunity may provide, Calumet shall make any modifications as may be required to ensure that Hydrogen Plant #3 heaters are equipped with appropriate sampling ports such that Method 201A and Method 202 testing could be accomplished if requested (ARM 17.8.105, ARM 17.8.1213).

J.26. Calumet shall monitor compliance with 40 CFR 60 Subpart J as required by 40 CFR 60 Subpart J (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart J).

J.27. Calumet shall monitor compliance with 40 CFR 60 Subpart Ja as required by 40 CFR 60 Subpart Ja (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

J.28. Calumet shall monitor compliance with 40 CFR 63 Subpart DDDDD as required by 40 CFR 63 Subpart DDDDD (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

J.29. Calumet shall monitor compliance with 40 CFR 60 Subpart GGG as required by 40 CFR 60 Subpart GGG (ARM 17.8.1213, ARM 17.8.302, ARM 17.8.340, and 40 CFR 60 Subpart GGG).

J.30. Calumet shall monitor compliance with 40 CFR 60 Subpart GGGa as required by 40 CFR 60 Subpart GGGa (ARM 17.8.1213, ARM 17.8.302, ARM 17.8.340, and 40 CFR 60 Subpart GGGa).

J.31. Calumet shall monitor compliance with 40 CFR 63 Subpart CC as required by 40 CFR 63 Subpart CC (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

J.32. Calumet shall monitor compliance with 40 CFR 60 Subpart QQQ as required by 40 CFR 60 Subpart QQQ (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

J.33. Calumet shall monitor compliance with 40 CFR 61 Subpart FF as required by 40 CFR 61 Subpart FF (ARM 17.8.1213, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Recordkeeping

J.34. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and must be submitted to DEQ upon request (ARM 17.8.1212).

J.35. Calumet shall comply with the NO_X and CO Umbrella limit related recordkeeping requirements of Section III.B.17 (ARM 17.8.1212).

J.36. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340, ARM 178.8.302, and 40 CFR 60 Subpart J).

J.37. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

J.38. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, AM 17.8.302, and 40 CFR 63 Subpart DDDDD).

J.39. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart GGG (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGG).

J.40. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart GGGa (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 63 Subpart GGGa).

J.41. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

J.42. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

J.43. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Reporting

J.44. No less than semiannually, Calumet shall submit a CEMS performance and excess emissions report for NO_X emissions from the #3 Hydrogen Plant furnace, in format equivalent to as submitted for NSPS Ja. Additionally, daily 30-day averages shall be submitted for days in which any excess emissions occurred (ARM 17.8.1212 and ARM 17.8.1213).

J.45. Calumet shall comply with the NO_X and CO Umbrella limit reporting requirements of Section III.B.26 (ARM 17.8.1212).

J.46. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302 and 40 CFR 60 Subpart J).

J.47. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302 and 40 CFR 60 Subpart Ja).

J.48. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302 and 40 CFR 63 Subpart DDDDD).

J.49. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart GGG (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302 and 40 CFR 60 Subpart GGG).

J.50. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart GGGa (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302 and 40 CFR 60 Subpart GGGa).

J.51. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302 and 40 CFR 63 Subpart CC).

J.52. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

J.53. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

J.54. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements.

J.55. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. summary of hydrogen plant #1, #2, and #3 NO_X and CO emissions as applicable
b. summary of hydrogen plant #3 CO_2 emissions
c. a summary of the of any source testing that was performed during the reporting period including date testing was performed, result of the test, and date the report was submitted or estimated to be submitted;
d. summary demonstrating compliance status with 40 CFR 60 Subpart J including reference to submittal dates or reports made or included;
e. summary demonstrating compliance status with 40 CFR 60 Subpart Ja including reference to submittal dates or reports made or included;
f. summary demonstrating compliance status with 40 CFR 63 Subpart DDDDD including reference to submittal dates or reports made or included;
g. summary demonstrating compliance status with 40 CFR 63 Subpart GGG including reference to submittal dates or reports made or included;
h. summary demonstrating compliance status with 40 CFR 63 Subpart GGGa including reference to submittal dates or reports made or included;

i. summary demonstrating compliance status with 40 CFR 63 Subpart CC including reference to submittal dates or reports made or included;
j. summary demonstrating compliance status with 40 CFR 60 Subpart QQQ including reference to submittal dates or reports made or included;
k. summary demonstrating compliance status with 40 CFR 61 Subpart FF including reference to submittal dates or reports made or included.

K. EU10 – POLYMER-MODIFIED ASPHALT UNIT

EU10a – Storage Tank #50
EU10b – Storage Tank #55
EU10c - Storage Tank #55 Heater
EU10d – Storage Tank #56
EU 10e - Storage Tank #56 Heater
EU10f – Storage Tank #69
EU10g – Storage Tank #110
EU10h – Storage Tank #110 Heater
EU10i – Storage Tank #102
EU10j – Storage Tank #112
EU10k - Storage Tank #112 Heater
EU10l – Storage Tank #130
EU10m – Storage Tank #130 Heater
EU10n – Storage Tank #132
EU10o – Storage Tank #132 Heater
EU10p – Storage Tank #133
EU10q – Storage Tank #133 Heater
EU10r – Storage Tank #135
EU10s – Storage Tank #135 Heater
EU10t – Storage Tank #137
EU10u – Storage Tank #137 Heater
EU10v – Storage Tank #138
EU10w – Storage Tank #138 Heater
EU10x – Storage Tank #139
EU10y – Storage Tank #139 Heater
EU10z – Storage Tank #140
EU10aa – Storage Tank #140 Heater
EU10bb – Equipment Components
EU10cc – Individual Drains

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Frequency	Reporting Requirements
K.1, K.13, K.22, K.38, K.39	VOC	Operational design and maintenance	Inspection	Ongoing	Semiannually
K.2, A.24, K.13, K.14, K.22, K.23, K.31, K.38, K.39	NSPS J SO_2: Tank Heaters for Tanks 55, 56, 110, 112, 130, 132, 133, 135, 137, 139, 140	40 CFR 60 Subpart J	Fuel Gas Monitoring	Continuous	Quarterly and 40 CFR 60 Subpart J
K.3, K.15, K.22, K.24, K.32, K.38, K.39	NSPS Ja SO_2: Tank Heater 138	40 CFR 60 Subpart Ja	Fuel Gas Monitoring	Continuous	40 CFR 60 Subpart Ja, Semiannual
K.4, K.16, K.22, K.25, K.30, K.33, K.38, K.39	MACT DDDDD: All tank heaters	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD and semiannual
K.5, K.17, K.22, K.26, K.34, K.38, K.39	MACT CC: Group II Tanks – All Tanks	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC and semiannual

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
K.6, K.18, K.22, K.27, K.35, K.38, K.39	NSPS UU: Tanks 50, 102, 137, 138, 139, 140	40 CFR 60 Subpart UU	40 CFR 60 Subpart UU	40 CFR 60 Subpart UU	40 CFR 60 Subpart UU and semiannual
K.5, K.17, K.22, K.26, K.34, K.38, K.39	MACT CC: leaks from equipment components	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC and semiannual
K.7, K.19, K.22, K.28, K.36, K.38, K.39	NSPS GGG: leaks from equipment components	40 CFR 60 Subpart GGG	40 CFR 60 Subpart GGG	40 CFR 60 Subpart GGG	40 CFR 60 Subpart GGG and semiannual
K.5, K.17, K.22, K.26, K.34, K.38, K.39	MACT CC: HAPs from individual drain system	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC and semiannual
K.8, K.20, K.22, K.29, K.37, K.38, K.39	NESHAP FF: benzene from individual drain system	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF and semiannual
K.9, K.21, K.22, K.38, K.39	Storage Tanks #50 and #102	Fixed Roof	Recordkeeping	Ongoing	Semiannual
K.10, K.21, K.22, K.38, K.39	Storage Tanks #50, 55, 56, 69, 102, 110, 112, 130, 132, 133, 135, 137, 139, 140	Heavy Oil use only	Recordkeeping	Ongoing	Semiannual
K.11, K.13, A.24, K.22, K.23, K.38, K.39	Asphalt Tank Heaters on Tanks #135, 137, 139, and 140	Natural Gas or NSPS J compliant fuel gas only	40 CFR 60 Subpart J	40 CFR 60 Subpart J	Quarterly and 40 CFR 60 Subpart J
K.12, K.13, A.24, K.22, K.23, K.38, K.39	Asphalt Tank Heaters on Tanks #130, 132, and 133	Natural Gas or NSPS J compliant fuel gas only	40 CFR 60 Subpart J	40 CFR 60 Subpart J	Quarterly and 40 CFR 60 Subpart J

Conditions

K.1. The PMA unit shall be operated and maintained as follows (ARM 17.8.752):

a. All open-ended valves shall have plugs or caps installed on the open end
b. All pumps in the PMA unit shall be equipped with standard single seals
c. All pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy service, and flanges and other connectors shall meet the standards described in 40

CFR 60.482-8. Repairs shall be made promptly as described in 40 CFR 60.482-7(e).

K.2. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart J, including as required by the consent decree and as applicable to heaters on tanks 55, 56, 110, 112, 130, 132, 133, 135, 137, 139, and 140 (ARM 17.8.1211, Consent Decree Paragraph 17.B, ARM 17.8.302, ARM 17.8.340, and 40 CFR 60 Subpart J).

K.3. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart Ja, including as applicable to the Tank 138 heater (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

K.4. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart DDDDD, including as applicable to all tank heaters (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

K.5. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart CC, including as applicable to all polymer modified asphalt unit tanks, equipment components in the polymer modified asphalt unit, and the individual drain system in the polymer modified asphalt unit (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

K.6. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture including as applicable to asphalt storage tanks 50, 102, 137, 138, 139, 140 (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart UU).

K.7. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart GGG including as applicable to the equipment components in the polymer modified asphalt unit (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGG).

K.8. Calumet shall comply with all applicable requirements of 40 CFR 61 Subpart FF including as applicable to the individual drain system in the polymer modified asphalt unit (ARM 17.8.1211, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

K.9. Storage tanks #50 and #102 shall be equipped with a fixed roof (ARM 17.8.752).

K.10. Storage tanks #50, #55, #56, #69, #102, #110, #112, #130, #132, #133, #135, #137, #139, and #140 shall be used for heavy oil (ARM 17.8.749).

K.11. Asphalt tank heaters #135, #137, #139, and #140 shall burn only natural gas or refinery fuel gas in compliance with 40 CFR 60 Subpart J (ARM 17.8.749, Consent Decree, and 40 CFR 60 Subpart J).

K.12. Tanks #130, #132, and #133, equipped with 0.75 MMBtu/hr tank heaters, shall burn natural gas or refinery fuel gas in compliance with 40 CFR 60 Subpart J (ARM 17.8.752, Consent Decree, and 40 CFR 60 Subpart J).

Compliance Demonstration

K.13. Calumet shall conduct inspection and maintain records monitoring compliance with Section III.K.1 (ARM 17.8.1213).

K.14. Calumet shall monitor compliance with 40 CFR 60 Subpart J as required by 40 CFR 60 Subpart J (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart J).

K.15. Calumet shall monitor compliance with 40 CFR 60 Subpart Ja as required by 40 CFR 60 Subpart Ja (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

K.16. Calumet shall monitor compliance with 40 CFR 63 Subpart DDDDD as required by 40 CFR 63 Subpart DDDDD (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

K.17. Calumet shall monitor compliance with 40 CFR 63 Subpart CC as required by 40 CFR 63 Subpart CC (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

K.18. Calumet shall monitor compliance with 40 CFR 60 Subpart UU as required by 40 CFR 60 Subpart UU (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart UU).

K.19. Calumet shall monitor compliance with 40 CFR 60 Subpart GGG as required by 40 CFR 60 Subpart GGG (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGG).

K.20. Calumet shall monitor compliance with 40 CFR 61 Subpart FF as required by 40 CFR 61 Subpart FF (ARM 17.8.1213, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

K.21. Calumet shall maintain onsite, and made available upon request, a map of tanks at the facility with Tank numbers clearly identified, and records of the capacity, design, and service of those tanks. Service changes shall be clearly logged, maintaining a history of the service of the tanks such that dates of service are maintained (ARM 17.8.1213).

Recordkeeping

K.22. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and must be submitted to DEQ upon request (ARM 17.8.1212).

K.23. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340, ARM 178.8.302, and 40 CFR 60 Subpart J).

K.24. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

K.25. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, AM 17.8.302, and 40 CFR 63 Subpart DDDDD).

K.26. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

K.27. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart UU (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart UU).

K.28. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart GGG (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGG).

K.29. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Reporting

K.30. Any compliance source test reports and/or logs must be submitted in accordance with Section III.A.2 (ARM 17.8.106 and ARM 17.8.1212).

K.31. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340, ARM 178.8.302, and 40 CFR 60 Subpart J).

K.32. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

K.33. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, AM 17.8.302, and 40 CFR 63 Subpart DDDDD).

K.34. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

K.35. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart UU (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart UU).

K.36. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart GGG (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGG).

K.37. Calumet shall comply with all applicable reporting requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

K.38. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements.

K.39. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. A summary highlighting inspection as required by Section III.K.13
b. A summary demonstrating compliance status with 40 CFR 60 Subpart J including reference to submittal dates or reports made or included

c. A summary demonstrating compliance status with 40 CFR 60 Subpart Ja including reference to submittal dates or reports made or included
d. A summary demonstrating compliance status with 40 CFR 63 Subpart DDDDD including reference to submittal dates or reports made or included
e. A summary demonstrating compliance status with 40 CFR 63 Subpart CC including reference to submittal dates or reports made or included
f. A summary demonstrating compliance status with 40 CFR 60 Subpart UU including reference to submittal dates or reports made or included
g. A summary demonstrating compliance status with 40 CFR 60 Subpart GGG including reference to submittal dates or reports made or included
h. A summary demonstrating compliance status with 40 CFR 61 Subpart FF including reference to submittal dates or reports made or included
i. A summary of any updates made to the records required by Section III.K.21
j. A summary of results of any testing that was performed on any of the storage units during the reporting period;

L. EU11 – MILD HYDROCRACKER UNIT

EU11a – MHC Combined Feed Heater H-4101
EU11b – MHC Fractionator Feed Heater H-4102
EU11c – Process Vents
EU11d – C01 Recycle Hydrogen Compressor
EU11e – C02a Hydrogen Compressor
EU11f – C02b Hydrogen Compressor
EU11g – C03a Off-gas Compressor
EU11h – C03b Off-gas Compressor
EU11i – Equipment Components
EU11j – Individual Drain System

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
L.1, L.27, L.35, L.42, L.43	H-4101 and H-4102 Maximum Rated Capacity	H-4101: 54.0 MMBtu/hr H-4102: 38.0 MMBtu/hr	Recordkeeping	Ongoing	Semiannual
L.2, L.15, L.29, L.36, L.42, L.43	H-4101 NO_X	0.035 lb/MMBtu	CEMS	Continuous	Semiannual
L.3, L.16, A.2, L.27, L.42, L.43	H-4102 NO_X	0.040 lb/MMBtu	Method 7E	Annually	Semiannual and Section III.A.2
L.4, L.17, L.27, L.42, L.43, A.2	H-4101 and H-4102 CO	0.055 lb/MMBtu	Source Test	Once per permit term	As required by DEQ and Section III.A.2

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
L.5, L.14, L.19, L.27, L.42, L.43, A.2	H-4101 and H-4102 CO_2e	141 lb/MMBtu	Recordkeeping of emissions based on fuel usage and established emissions factors	Ongoing	Semiannual
L.6, L.18, L.27, L.28, L.35, L.42, L.43	H-4101 and H-4102: NO_X and CO Umbrella Limit Affected Units	Section III.B.5 and III.B.6	NO_X: CEMS CO: Average emissions factor from portable analyzer + fuel usage	Ongoing	Semiannual
L.7, L.20, L.27, L.42, L.43, A.2	H-4101 and H-4102 PM/PM_{10}, and $PM_{2.5}$	PM and PM_{10}: 0.00051 lb/MMBtu $PM_{2.5}$: 0.00042 lb/MMBtu	Source Test	As required by DEQ and Section III.A.1	As required by DEQ and Section III.A.2
L.8, L.21, L.27, L.29, L.36, L.42, L.43	NSPS Ja SO_2/H_2S: H-4101 and H-4102	162 ppmv on a 3-hr average basis and 60 ppmv determined daily on a 365 succesive calendar day rolling average basis	NSPS Ja Fuel Gas H_2S CMS	Continuous	Semiannual and 40 CFR 60 Subpart Ja
L.8, L.15, L.21, L.27, L.29, L.36, L.42, L.43	NSPS Ja NO_X: H-4101	40 ppmvd at 0% O_2 determined daily on a 30-day rolling average, or 0.040 lb/MMBtu-HHV on a 30-day rolling average	NO_X CEMS	Continuous	Semiannual and 40 CFR 60 Subpart Ja
L.9, L.22, L.30, L.37, L.42, L.43	MACT DDDDD: HAPs from H-4101 and H-4102	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	Semiannual and 40 CFR 63 Subpart DDDDD
L.10, L.23, L.33, L.38, L.42, L.43	MACT CC: HAPs from process vents	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
L.10, L.23, L.33, L.38, L.42, L.43	MACT CC: HAPs from equipment components	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
L.10, L.23, L.33, L.38, L.42, L.43	MACT CC: HAPs from individual drain system	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
L.11, L.24, L.31, L.39, L.42, L.43	NSPS GGGa: VOC from equipment components	40 CFR 60 Subpart GGGa	40 CFR 60 Subpart GGGa	40 CFR 60 Subpart GGGa	Semiannual and 40 CFR 60 Subpart GGGa
L.12, L.25, L.32, L.40, L.42, L.43	NSPS QQQ: VOC from individual drain system	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	Semiannual and 40 CFR 60 Subpart QQQ
L.13, L.26, L.34, L.41, L.42, L.43	NESHAP FF: benzene from individual drain system	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	Semiannual and 40 CFR 61 Subpart FF

Conditions

L.1. The maximum rated capacity of the H-4101 and H-4102 shall not exceed 54.0 and 38.0 MMBtu/hr, respectively (ARM 17.8.1212 and ARM 17.8.749).

L.2. The H-4101 shall be equipped with ULNB and NO_X emissions shall not exceed 0.035 lb/MMBtu-HHV based on a 30-day rolling average (ARM 17.8.1211, ARM 17.8.749, ARM 17.8.752).

L.3. The H-4102 shall be equipped with ULNB and NO_X emissions shall not exceed 0.040 lb/MMBtu-HHV based on a 3-hour average (ARM 17.8.1211, ARM 17.8.752).

L.4. CO emissions from the H-4101 and H-4102 shall not exceed 0.055 lb/MMBtu (ARM 17.8.752).

L.5. CO_2e emissions from the H-4101 and H-4102 heaters shall not exceed 141 lb/MMBtu. (ARM 17.8.1212 and ARM 17.8.752).

L.6. Calumet shall comply with the NO_X and CO Umbrella Limitations of Section III.B.5 and III.B.6. The H-4101 and H-4102 are affected units (ARM 17.8.1211 and ARM 17.8.749).

L.7. Calumet shall control PM, PM_{10}, and $PM_{2.5}$ emissions from each heater by utilizing good combustion practices and only combusting low sulfur fuels. Particulate emissions from the H-4101 and H-4102 shall not exceed the following (ARM 17.8.752):

a. PM and PM_{10} emissions: 0.00051 lb/MMBtu
b. $PM_{2.5}$ emissions: 0.00042 lb/MMBtu

L.8. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart Ja, including as applicable to the MHC Combined Feed Heater H-4101 for NO_X and SO_2/H_2S, and MHC Fractionator Feed Heater H-4102 for SO_2/H_2S (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, 40 CFR 60 Subpart Ja).

L.9. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart DDDDD, as applicable to the MHC Combined Feed Heater H-4101 and MHC Fractionator Feed Heater H-4102 (ARM 17.08.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

L.10. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart CC, including as applicable to the process vents, equipment components, and the individual drain system in the mild hydrocracking unit (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

L.11. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart GGGa, including as applicable to equipment components in the mild hydrocracking unit and the C01, C02a, C02b, C03a, and C03b compressors (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGGa).

L.12. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ, including as applicable to the individual drain system in the mild hydrocracking unit (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

L.13. Calumet shall comply with all applicable requirements of 40 CFR 61 Subpart FF, including as applicable to the individual drain system in the mild hydrocracking unit (ARM 17.8.1211, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Compliance Demonstration

L.14. Calumet shall maintain on-site and available upon request, documentation of the maximum rated capacity of the H-4101 and H-4102 (ARM 17.8.1213).

L.15. The Mild Hydrocracker Heater H-4101 shall be equipped with NO_X CEMS in compliance with 40 CFR 60 Subpart A and Ja by no later than June 30, 2018 (ARM 17.8.749).

L.16. Once every calendar year, Calumet shall test H-4102 for NO_X emissions utilizing Method 7E. Fuel usage during the test and fuel analysis taken from fuel used during the test shall be determined to report an average lb/MMBtu value. The lb/MMBtu value shall be used to monitor compliance with the limitation of Section III.L.3 and as the emissions factor for use in determining mass emissions of NO_X for Umbrella limit recordkeeping (ARM 17.8.1213).

L.17. Once during the term of this permit, Calumet shall conduct a CO test utilizing Method 10, and utilizing fuel analyses taken from the day of the testing, determine the lb/MMBtu emissions against the limitation of Section III.L.4. All CO testing shall be concurrent with NO_X testing. (ARM 17.8.1213).

L.18. Calumet shall utilize a CO emissions factor derived as the average of all portable analyzer testing results completed, and continuously monitor fuel usage in each unit, to monitor mass

emissions of CO from the H-4101 and H-4102 heaters for purposes of the CO Umbrella Limit monitoring, until a CO test is performed. After such test is performed, Calumet shall utilize the emissions factor determined in the last source test. By no later than the 25th of each month, Calumet shall determine the monthly and rolling 12-month sum of mass emissions of CO from each unit (ARM 17.8.1213).

L.19. Calumet shall monitor compliance with the CO_2e emissions limitations of Section III.D.8 by tracking fuel usage and utilizing established emissions factors as used for greenhouse gas emissions reporting. (ARM 17.8.105, ARM 17.8.1213).

L.20. Calumet shall maintain records demonstrating utilization of good combustion practices, and combusting low sulfur fuels. NSPS Ja fuel gas H_2S records may be utilized to monitor low sulfur fuel combustion. As required by DEQ and Section III.A.1, Calumet shall test the H-4101 and H-4102 heaters utilizing Method 201 and 202. During the next refinery turnaround or as opportunity may provide, Calumet shall make any modifications as may be required to ensure that H-4101 and H-4102 is equipped with appropriate sampling ports such that Method 201A and Method 202 testing could be accomplished if requested (ARM 17.8.105, ARM 17.8.1213).

L.21. Calumet shall monitor compliance with 40 CFR 60 Subpart Ja as required by 40 CFR 60 Subpart Ja (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

L.22. Calumet shall monitor compliance with 40 CFR 63 Subpart DDDDD as required by 40 CFR 63 Subpart DDDDD (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

L.23. Calumet shall monitor compliance with 40 CFR 63 Subpart CC as required by 40 CFR 63 Subpart CC (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

L.24. Calumet shall monitor compliance with 40 CFR 60 Subpart GGGa as required by 40 CFR 60 Subpart GGGa (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGGa).

L.25. Calumet shall monitor compliance with 40 CFR 60 Subpart QQQ as required by 40 CFR 60 Subpart QQQ (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

L.26. Calumet shall monitor compliance with 40 CFR 61 Subpart FF as required by 40 CFR 61 Subpart FF (ARM 17.8.1213, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Recordkeeping

L.27. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and must be submitted to DEQ upon request (ARM 17.8.1212).

L.28. Calumet shall comply with the NO_X and CO Umbrella limit recordkeeping requirement of Section III.B.17 for H-4101 and H-4102 (ARM 17.8.1212).

L.29. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

L.30. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, AM 17.8.302, and 40 CFR 63 Subpart DDDDD).

L.31. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart GGGa (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGGa).

L.32. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

L.33. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

L.34. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Reporting

L.35. Calumet shall comply with the NO_X and CO Umbrella limit reporting requirements of Section III.B.26 (ARM 17.8.1212).

L.36. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

L.37. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, AM 17.8.302, and 40 CFR 63 Subpart DDDDD).

L.38. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

L.39. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart GGGa (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGGa).

L.40. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

L.41. Calumet shall comply with all applicable reporting requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

L.42. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements.

L.43. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. The report required by Section III.B.26, or reference to it if submitted separately
b. A summary of data demonstrating compliance with the lb/MMBtu NO_X limit on H-4101 and H-4102;
c. A summary of any source testing that was performed during the reporting period including date testing was performed, result of the test, and date the report was submitted or estimated to be submitted;
d. Summary of CO_2e emissions as kept by Section III.L.19;
e. A summary demonstrating compliance status with 40 CFR 60 Subpart Ja including reference to submittal dates or reports made or included;
f. A summary demonstrating compliance status with 40 CFR 63 Subpart DDDDD including reference to submittal dates or reports made or included;
g. A summary demonstrating compliance status with 40 CFR 63 Subpart CC including reference to submittal dates or reports made or included;
h. A summary demonstrating compliance status with 40 CFR 60 Subpart GGGa including reference to submittal dates or reports made or included;
i. A summary demonstrating compliance status with 40 CFR 60 Subpart QQQ including reference to submittal dates or reports made or included;
j. A summary demonstrating compliance status with 40 CFR 61 Subpart FF including reference to submittal dates or reports made or included;
k. A summary of results of any testing and reference to source test submittal date.

M. EU12 – HYDROTREATER UNIT

EU12a: Kerosene Heater
EU12b: HTU Heater (HDS Furnace Stack)
EU12c: Process Vents
EU12d: Equipment Components
EU12e: Individual Drain System

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
M.1, M.9, M.16, M.29, M.30	NO_X emissions from the HTU Heater	0.07 lb/MMBtu 1.58 lb/hr 6.9 ton/yr	Method 7 with emissions factor development and monthly calc	Method 7: Once during permit term Ton/yr: Monthly	Semiannual and Section III.A.2
M.2, M.9, M.16, M.29, M.30	CO emissions from the HTU Heater	0.88 lb/hr 3.84 ton/yr	Method 10 with emissions factor development and monthly calc	Method 10: Once during permit term Ton/yr: Monthly	Semiannual and Section III.A.2
M.3, M.10, A.24, M.16, M.17, M.23, M.29, M.30	40 CFR 60 Subpart J: H_2S in Fuel Gas Units Kerosene Heater and HTU Heater	162 ppmv on a 3-hr average basis	Fuel Gas H_2S CMS	Continuous	Quarterly and 40 CFR 60 Subpart J

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
M.4, M.11, M.16, M.18, M.24, M.29, M.30	MACT DDDDD: HAPs from HTU and Kerosene Heaters	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	Semiannual and 40 CFR 63 Subpart DDDDD
M.5, M.12, M.16, M.21, M.25, M.29, M.30	MACT CC: HAPs from process vents	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
M.5, M.12, M.16, M.21, M.25, M.29, M.30	MACT CC: HAPs from Equipment Components	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
M.6, M.13, M.16, M.19, M.26, M.29, M.30	NSPS GGG: VOC from equipment components	40 CFR 60 Subpart GGG	40 CFR 60 Subpart GGG	40 CFR 60 Subpart GGG	Semiannual and 40 CFR 60 Subpart GGG
M.7, M.14, M.16, M.20, M.27, M.29, M.30	NSPS QQQ: VOC from Wastewater Individual Drain System	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	Semiannual and 40 CFR 60 Subpart QQQ
M.5, M.12, M.16, M.21, M.25, M.29, M.30	MACT CC: HAPs from Wastewater Individual Drain System	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
M.8, M.15, M.16, M.22, M.28, M.29, M.30	NESHAP FF: benzene from Wastewater Individual Drain System	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	Semiannual and 40 CFR 61 Subpart FF

Conditions

M.1. NO_X emissions from the HTU Heater (HDS Furnace Stack) shall not exceed the following (ARM 17.8.1211 and ARM 17.8.752):

a. 0.07 lb/MMBtu
b. 1.58 lb/hr
c. 6.9 TPY

M.2. CO emissions from the HTU Heater (HDS Furnace Stack) shall not exceed the following (ARM 17.8.1211 and ARM 17.8.752):

a. 0.88 lb/hr
b. 3.84 TPY

M.3. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart J, including as applicable to the Kerosene and HTU (HDS) heaters (Consent Decree, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart J).

M.4. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart DDDDD, including as applicable to the Kerosene and HTU (HDS) heaters (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

M.5. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart CC, including as applicable to process vents, equipment components, and the individual drain system of the hydrotreater unit (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 60 Subpart CC).

M.6. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart GGG, including as applicable to equipment components of the hydrotreater unit (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGG).

M.7. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ, including as applicable to the individual drain system of the hydrotreater unit (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

M.8. Calumet shall comply with all applicable requirements of 40 CFR 61 Subpart FF, including as applicable to the individual drain system of the hydrotreater unit (ARM 17.8.1211, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Compliance Demonstration

M.9. Calumet shall, utilizing an emissions factor determined during the last source test, track actual fuel burning rates to monitor compliance against the NO_X and CO TPY emissions limitations of Section III.M.1 and III.M.2. By the 25th of each month, Calumet shall calculate and record the monthly and rolling 12-month sum of emissions. Once during the term of this permit, Calumet shall test the heaters for NO_X and CO, concurrently, to monitor compliance against the rate based and hourly limitations of Section III.M.1 and III.M.2 (ARM 17.8.1213).

M.10. Calumet shall monitor compliance with 40 CFR 60 Subpart J as required by 40 CFR 60 Subpart J (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart J).

M.11. Calumet shall monitor compliance with 40 CFR 63 Subpart DDDDD as required by 40 CFR 63 Subpart DDDDD (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

M.12. Calumet shall monitor compliance with 40 CFR 63 Subpart CC as required by 40 CFR 63 Subpart CC (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

M.13. Calumet shall monitor compliance with 40 CFR 60 Subpart GGG as required by 40 CFR 60 Subpart GGG (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGG).

M.14. Calumet shall monitor compliance with 40 CFR 60 Subpart QQQ as required by 40 CFR 60 Subpart QQQ (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

M.15. Calumet shall monitor compliance with 40 CFR 61 Subpart FF as required by 40 CFR 61 Subpart FF (ARM 17.8.1213, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Recordkeeping

M.16. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and must be submitted to DEQ upon request (ARM 17.8.1212).

M.17. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart J).

M.18. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, AM 17.8.302, and 40 CFR 63 Subpart DDDDD).

M.19. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart GGG (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGG).

M.20. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

M.21. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

M.22. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Reporting

M.23. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart J).

M.24. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, AM 17.8.302, and 40 CFR 63 Subpart DDDDD).

M.25. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

M.26. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart GGG (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGG).

M.27. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

M.28. Calumet shall comply with all applicable reporting requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

M.29. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements.

M.30. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. A summary of the of any source testing that was performed during the reporting period including date testing was performed, result of the test, and date the report was submitted or estimated to be submitted;
b. The monthly and rolling 12-month sum of NO_X and CO emissions from the Kerosene and HTU Heaters
c. A summary demonstrating compliance status with 40 CFR 60 Subpart J including reference to submittal dates or reports made or included;
d. A summary demonstrating compliance status with 40 CFR 63 Subpart DDDDD including reference to submittal dates or reports made or included;
e. A summary demonstrating compliance status with 40 CFR 63 Subpart CC including reference to submittal dates or reports made or included;
f. A summary demonstrating compliance status with 40 CFR 60 Subpart GGG including reference to submittal dates or reports made or included;
g. A summary demonstrating compliance status with 40 CFR 60 Subpart QQQ including reference to submittal dates or reports made or included;
h. A summary demonstrating compliance status with 40 CFR 61 Subpart FF including reference to submittal dates or reports made or included.

N. EU13 – FLARE #1 & #2, Flare Gas Scrubber Equipment Components

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
N.1, N.3, N.13, N.14, N.20, N.21, N.27, N.32, N.33	Flare #1 - Scrubber	Equipped with flare gas scrubber and NSPS Ja	NSPS Ja	NSPS Ja	Semiannual and 40 CFR 60 Subpart Ja
N.2, N.12, N.20, N.32, N.33	Flare #2:	Emergency /Startup/ Shutdown/ Malfunction use only	Recordkeeping	Continuous	Semiannual
N.4, N.15, N.20, N.28, N.32, N.33	MACT CC: HAPs from process vents	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
N.4, N.15, N.20, N.28, N.32, N.33	MACT CC: HAPs from Equipment Components	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
N.5, N.16 N.22, N.29, N.32, N.33	NSPS GGGa: VOC from equipment components	40 CFR 60 Subpart GGGa	40 CFR 60 Subpart GGGa	40 CFR 60 Subpart GGGa	Semiannual and 40 CFR 60 Subpart GGGa/VVa

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
N.10, N.17, N.23, N.30, N.32, N.33	NSPS QQQ: VOC from Wastewater Individual Drain System	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	Semiannual and 40 CFR 60 Subpart QQQ
N.4, N.15, N.24, N.28, N.32, N.33	MACT CC: HAPs from Wastewater Individual Drain System	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
N.11, N.18, N.25, N.31, N.32, N.33	NESHAP FF: benzene from Wastewater Individual Drain System	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	Semiannual and 40 CFR 61 Subpart FF
N.6, N.19, N.20, N.32, N.33	Old Sour Water Stripper	Reactivation Review Required	Recordkeeping	Ongoing	Semiannual
N.9, A.24, N.32, N.33	Consent Decree Requirements	500 lb SO_2 in any 24-hr period	investigative, reporting, and corrective action procedures	As required	Semiannual and Consent Decree

Conditions

N.1. Flare #1 (Primary Flare) shall be equipped with a flare gas scrubber (ARM 17.8.1211, ARM 17.8.749, ARM 17.8.752).

N.2. Flare #2 (secondary flare) must maintain a water seal except during periods of startup, shutdown, or malfunction. These periods of startup, shutdown, and malfunction shall not exceed 9 hours per year based on a 12-month rolling average (ARM 17.8.1211, ARM 17.8.749).

N.3. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart Ja, including as applicable to Flare #1 and #2 (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

N.4. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart CC, including as applicable to the flares and equipment components of the NaHS Fuel Gas Scrubber Unit (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

N.5. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart GGGa, including as applicable to the NaHS equipment components. (ARM 17.8.1211, ARM 17.8.3452, ARM 17.8.302, and 40 CFR 60 Subpart GGGa).

N.6. Calumet shall not re-activate the old sour water stripper unit that was taken out of stripping service in 2006, without conducting a permitting analysis in conformance with ARM 17.8 Subchapter 7, and obtaining Department approval, in writing (ARM 17.8.749).

N.7. For purposes of streamlining, instead of complying with 40 CFR 60.11(d) as indicated by the Consent Decree, Calumet shall comply with the NSPS obligation to implement good air pollution control practices by complying with the flare requirements as outline in 40 CFR 63 Subpart CC (ARM 17.8.1211, Consent Decree, ARM 17.8.302, ARM 17.8.342, and 40 CFR 63 Subpart CC – Streamlined condition identifying MACT CC as demonstrating compliance with good air pollution control practices as required by NSPS).

N.8. For purposes of streamlining, instead of complying with the reporting requirements of 40 CFR 60 Subpart J for the flares as required by Consent Decree Paragraph 19.D, Calumet shall comply with reporting requirements of 40 CFR 60 Subpart Ja, and 40 CFR 63 Subpart CC (ARM 17.8.1211, Consent Decree, ARM 17.8.302, ARM 17.8.340, ARM 17.8.342, 40 CFR 60 Subpart Ja, and 40 CFR 63 Subpart CC).

N.9. Pursuant to the Consent Decree, Paragraph 21, Calumet shall, for all Hydrocarbon Flaring Incidents (as defined in the Consent Decree – 500 lb SO_2 in any 24-hr period), follow the investigative, reporting, and corrective action procedures as outline in paragraphs 20.A-20.B (ARM 17.8.1211, Consent Decree Paragraph 21).

N.10. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart QQQ including as applicable to the individual drain system of the flare gas scrubber (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

N.11. Calumet shall comply with all applicable requirements of 40 CFR 61 Subpart FF including as applicable to the individual drain system of the flare gas scrubber (ARM 17.8.1211, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Compliance Demonstration

N.12. Calumet shall document any timeframe in which flare #2 operates. By the 25th of each month, Calumet shall calculate and record the monthly hours of flaring, and the rolling 12-month average hours of operation (ARM 17.8.1213, ARM 17.8.749).

N.13. Calumet shall comply with Section III.N.1 by utilizing compliance monitoring mechanisms as provided in 40 CFR 60 Subpart Ja (ARM 17.8.1213).

N.14. Calumet shall monitor compliance with 40 CFR 60 Subpart Ja as required by 40 CFR 60 Subpart Ja, including the alternative monitoring plan for Total Reduced Sulfur Monitoring at the flares approved by EPA in correspondence date stamped August 14, 2019, and agreed to by Calumet (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

N.15. Calumet shall monitor compliance with 40 CFR 63 Subpart CC as required by 40 CFR 63 Subpart CC (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

N.16. Calumet shall monitor compliance with 40 CFR 60 Subpart GGGa as required by 40 CFR 60 Subpart GGGa (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGGa).

N.17. Calumet shall monitor compliance with 40 CFR 60 Subpart QQQ as required by 40 CFR 60 Subpart QQQ (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

N.18. Calumet shall monitor compliance with 40 CFR 61 Subpart FF as required by 40 CFR 61 Subpart FF (ARM 17.8.1213, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

N.19. Calumet shall maintain records of sour water stripper operations and Department reviews, for the old sour water stripper or any new sour water stripper (ARM 17.8.1213).

Recordkeeping

N.20. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and must be submitted to DEQ upon request (ARM 17.8.1212).

N.21. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

N.22. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart GGGa (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGGa).

N.23. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

N.24. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

N.25. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Reporting

N.26. Calumet shall comply with the NO_X and CO Umbrella limit reporting requirements of Section III.B.26B.24. (ARM 17.8.1212).

N.27. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

N.28. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

N.29. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart GGGa (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart GGGa).

N.30. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

N.31. Calumet shall comply with all applicable reporting requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

N.32. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements.

N.33. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. The monthly and rolling 12-month flare operation time as required by Section III.N.12
b. A summary of any source testing that was performed during the reporting period including date testing was performed, result of the test, and date the report was submitted or estimated to be submitted;
c. A summary explanation of compliance status with Section III.N.6
d. A summary demonstrating compliance status with 40 CFR 60 Subpart Ja including reference to submittal dates or reports made or included;
e. A summary demonstrating compliance status with 40 CFR 63 Subpart CC including reference to submittal dates or reports made or included;
f. A summary demonstrating compliance status with 40 CFR 60 Subpart GGGa including reference to submittal dates or reports made or included;
g. A summary demonstrating compliance status with 40 CFR 60 Subpart QQQ including reference to submittal dates or reports made or included;
h. A summary demonstrating compliance status with 40 CFR 61 Subpart FF including reference to submittal dates or reports made or included.

O. EU14 – PRODUCT LOADING

EU14a: Truck Loading Rack and VCU
EU14b: Railcar Loading Rack and VCU

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration		Reporting Requirements
			Method	Frequency	
O.1, O.10, O.12, O.13, O.16, O.17, O.24, O.35, O.36	Gasoline Truck Loading Rack VCU Emissions	VOC: 10 mg/L CO: 10 mg/L NO_X: 4 mg/L PM: 0.10 gr/dscf @ 12% CO_2	Source Testing and Operating Parameters	Ongoing	Semiannual and Section III.A.2
O.2, O.10, O.14, O.15, O.16, O.18, O.24, O.35, O.36	Gasoline Railcar Loading Rack VCU Emissions	VOC: 10 mg/L CO: 10 mg/L NO_X: 4 mg/L PM: 0.10 gr/dscf @ 12% CO_2	Source Testing and Operating Parameters	Ongoing	Semiannual and Section III.A.2

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
O.3, O.5, O.6, O.7, O.8, O.9, O.10, O.11, O.12, O.13, O.14, O.15, O.16, O.17, O.18, O.19, O.20, O.21, O.22, O.23, O.24, O.25, O.26, O.27, O.28, O.29, O.30, O.31, O.32, O.33, O.34, O.35, O.36	Truck Loading Rack Operations Requirements	Truck Loading Rack Operations Requirements	Recordkeeping	Ongoing	Semiannual
O.4, O.5, O.6, O.7, O.8, O.9, O.10, O.11, O.12, O.13, O.14, O.15, O.16, O.17, O.18, O.19, O.20, O.21, O.22, O.23, O.24, O.25, O.26, O.27, O.28, O.29, O.30, O.31, O.32, O.33, O.34, O.35, O.36	Railcar Loading Rack Operations Requirements	Railcar Loading Rack Operations Requirements	Recordkeeping	Ongoing	Semiannual
O.6, O.21, O.24, O.27, O.32, O.35, O.36	MACT EEEE	40 CFR 63 Subpart EEEE	40 CFR 63 Subpart EEEE	40 CFR 63 Subpart EEEE	Semiannual and 40 CFR 63 Subpart EEEE
O.5, O.19, O.24, O.25, O.30, O.35, O.36	MACT R	40 CFR 63 Subpart R	40 CFR 63 Subpart R	40 CFR 63 Subpart R	Semiannual and 40 CFR 63 Subpart R
O.7, O.20, O.24, O.26, O.31, O.35, O.36, O.8, O.22, O.24, O.28, O.33, O.35, O.36	MACT CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration		Reporting Requirements
			Method	Frequency	
O.8, O.22, O.24, O.28, O.33, O.35, O.36	NSPS QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	Semiannual and 40 CFR 60 Subpart QQQ
O.9, O.23, O.24, O.29, O.34, O.35, O.36	NESHAP FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	Semiannual and 40 CFR 61 Subpart FF

Conditions

O.1. Emissions from the gasoline truck loading rack vapor combustion unit (VCU) shall not exceed the following (ARM 17.8.1211):

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, ARM 17.8.302 and 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. Visible emissions shall not exceed an opacity of 10% (ARM 17.8.752).

e. Particulate of 0.10 gr/dscf corrected to 12% carbon dioxide (CO_2) (ARM 17.8.752).

O.2. Emissions from the gasoline railcar loading rack VCU shall not exceed the following (ARM 17.8.1211):

a. The total VOC emissions to the atmosphere from the VCU due to loading gasoline into railcars shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.342 and 40 CFR Part 63.422, and ARM 17.8.752).

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

d. Calumet 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 (averaged over 6 consecutive minutes in accord to Method 9) (ARM 17.8.752); and

ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO_2 (ARM 17.8.752).

O.3. The gasoline and distillates truck loading rack shall be operated and maintained as follows (ARM 17.8.1211):

a. Calumet's tank truck loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from cargo tanks during gasoline product loading (ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart R).

b. Calumet collected vapors shall be routed to the VCU at all times. In the event the VCU is inoperable, Calumet may continue to load 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).

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

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

e. The vapor collection system shall be designed to prevent any VOC vapors collected at one loading position from passing to another loading position (ARM 17.8.342).

f. Loadings of liquid products into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks, using the following procedures (ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart R):

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

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

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

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

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

A. The gasoline cargo tank meets the applicable test requirements in 40 CFR 63.425(e);

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

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

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

g. Calumet shall ensure that loadings of gasoline cargo tanks at the truck loading rack are made only into cargo tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system (ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart R).

h. Calumet shall ensure that the terminal and the cargo tank vapor recovery systems are connected during each loading of a gasoline cargo tank at the truck loading rack (ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart R).

i. Calumet shall monitor and maintain all pumps, shutoff valves, relief valves, and other piping and valves associated with the gasoline loading rack as described in 40 CFR 60.482-1 through 60.482-10 (ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart R).

j. The truck loading rack VCU stack shall be at least 35 feet above grade (ARM 17.8.749).

O.4. The gasoline railcar loading rack and VCU shall be operated and maintained as follows (ARM 17.8.1211):

a. Gasoline and naphtha will be the only products loaded from the gasoline railcar loading rack (ARM 17.8.749).

b. Calumet's gasoline railcar loading rack shall be equipped with a vapor recovery system designed to collect the organic compounds displaced from railcar product loading and vent those emissions to the VCU (ARM 17.8.342 and 40 CFR 63, Subpart CC and ARM 17.8.752).

c. Calumet shall operate and maintain the VCU to control VOC and hazardous air pollutant (HAP) emissions during the loading of gasoline or naphtha in the gasoline railcar loading rack. Calumet's collected vapors shall be routed to the VCU at all times (ARM 17.8.752).

d. The vapor recovery system shall be designed to prevent any VOC vapors collected at one loading position from passing to another loading position (ARM 17.8.749).

e. Loading of gasoline and naphtha railcars shall be restricted to the use of submerged fill and dedicated normal service (ARM 17.8.752).

f. Calumet shall ensure that loading of railcars at the gasoline railcar loading rack are made only into railcars equipped with vapor recovery equipment that is compatible with the terminal's vapor recovery system (ARM 17.8.749).

g. Loadings of gasoline into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks, using procedures as listed in 40 CFR 63 Subpart R (ARM 17.8.342 and 40 CFR 63, Subpart CC, and ARM 17.8.752).

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

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

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

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

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

      A. The gasoline cargo tank meets the applicable test requirements in 40 CFR 63.425(e);

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

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

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

h. Calumet shall ensure that the terminal's and the railcar's vapor recovery systems are connected during each loading of a railcar at the gasoline railcar loading rack (ARM 17.8.749).

i. The vapor recovery and liquid loading equipment shall be designed and operated to prevent gauge pressure in the gasoline railcar from exceeding 4,500 Pa (450 mm of water) during gasoline loading. This level shall not be exceeded when measured by the procedures specified in 40 CFR 60.503(d) (ARM 17.8.342 and 40 CFR 63, Subpart CC).

j. No pressure-vacuum vent in the permitted terminal's vapor recovery system shall begin to open at a system pressure less than 4,500 Pa (450 mm of water) (ARM 17.8.749).

k. Calumet shall comply with the applicable provisions of 40 CFR 60, Subpart VV, including Calumet shall monitor and maintain all pumps, shutoff valves, relief valves, and other piping and valves associated with the gasoline loading rack as described in 40 CFR 60.482-1 through 60.482-10 (ARM 17.8.749, ARM 17.8.342 and 40 CFR 63, Subpart CC).

l. The gasoline railcar loading rack VCU stack exhaust exit shall be at least 30 feet above grade (ARM 17.8.749).

O.5. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart R – National Emission Standards for Gasoline Distribution Facilities, including as applicable to the truck and railcar loading rack (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart R).

O.6. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart EEEE – National Emissions Standards for Hazardous Air Pollutants: Organic Liquids Distribution (non-gasoline), including as applicable to the Railcar loading rack when loading Naptha (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart EEEE).

O.7. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart CC, including as applicable to the truck loading rack, truck rack equipment components, truck rack individual drain system, railcar loading rack, railcar rack equipment components, and railcar loading rack individual drain system (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

O.8. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ, including as applicable to the individual drain system of the truck and railcar loading rack (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

O.9. Calumet shall comply with all applicable requirements of 40 CFR 61 Subpart FF, including as applicable to the individual drain system of the truck and railcar loading rack (ARM 17.8.1211, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Compliance Demonstration

O.10. For both the gasoline truck loading rack and the gasoline railcar loading rack, Calumet shall install, calibrate, certify, operate and maintain a thermocouple with an associated recorder as a continuous parameter monitoring system (CPMS). A CPMS shall be located in each VCU firebox or in the ductwork immediately downstream from the firebox in a position before any substantial heat exchange occurs in accordance with 40 CFR 63.427, in order to monitor compliance with 40 CFR 63, Subpart R. Calumet shall operate the VCUs in a manner not to go below the operating parameter values established using the procedures in 40 CFR 63.425 (ARM 17.8.342 and 40 CFR 63, Subpart CC).

O.11. Calumet shall comply with all test methods and procedures as specified by 40 CFR 63.425(a) through (c), and 63.425(e) through (h). This shall apply to, but not be limited to, the gasoline

and distillate truck loading rack, the gasoline railcar loading rack, the vapor processing systems, and all gasoline equipment (ARM 17.8.1212).

O.12. The gasoline truck loading rack VCU shall be tested for total organic compounds on an every 5-year basis or according to another testing/monitoring schedule as may be approved by DEQ. Calumet shall perform the test methods and procedures as specified in 40 CFR 63.425 (ARM 17.8.1213, ARM 17.8.105).

O.13. The gasoline truck loading rack VCU shall be tested for CO and NO_X on an every 5 year basis or according to another testing/monitoring schedule as may be approved by DEQ (ARM 17.8.1213, ARM 17.8.105).

O.14. The gasoline railcar loading rack VCU shall be initially tested for total organic compounds within 180 days of initial startup. Additional testing shall occur on an every 5-year basis or according to another testing/monitoring schedule as may be approved by DEQ. Calumet shall perform the test methods and procedures as specified in 40 CFR 63.425 (ARM 17.8.105 and 17.8.342).

O.15. The gasoline railcar loading VCU shall be initially tested for CO and NO_X, concurrently, within 180 days of initial startup (ARM 17.8.105). Once during the term of this permit, Calumet shall test the VCU for NO_X and CO, concurrently (ARM 17.8.1213, ARM 17.8.105).

O.16. Fuel flow rates, production information, and any other data DEQ believes is necessary shall be recorded during the performance of source tests (ARM 17.8.749).

O.17. Gasoline Truck Loading Rack VCU Compliance determinations for VOC, NO_X and CO emission limits for the gasoline truck loading rack VCU shall be based upon the most recent compliance source test as well as compliance with the designated operating parameter value using the thermocouple and recorder (ARM 17.8.1213).

O.18. Gasoline Railcar Loading Rack VCU compliance determinations for VOC, NO_X and CO emission limits for the gasoline railcar loading rack VCU shall be based upon the most recent compliance source test as well as compliance with the designated operating parameter value using the thermocouple and recorder (ARM 17.8.1213).

O.19. Calumet shall comply with all compliance demonstration requirements of 40 CFR 63 Subpart R (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart R).

O.20. Calumet shall comply with all compliance demonstration requirements of 40 CFR 63 Subpart CC (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

O.21. Calumet shall comply with all compliance demonstration requirements of 40 CFR 63 Subpart EEEE (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart EEEE).

O.22. Calumet shall comply with all compliance demonstration requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

O.23. Calumet shall comply with all compliance demonstration requirements of 40 CFR 61 Subpart FF (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Recordkeeping

O.24. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and must be submitted to DEQ upon request (ARM 17.8.1212).

O.25. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart R (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart R).

O.26. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

O.27. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart EEEE (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart EEEE).

O.28. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

O.29. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Reporting

O.30. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart R (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart R).

O.31. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

O.32. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart EEEE (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart EEEE).

O.33. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

O.34. Calumet shall comply with all applicable reporting requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 61 Subpart FF).

O.35. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements.

O.36. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. A summary of the of any source testing that was performed during the reporting period including date testing was performed, result of the test, and date the report was submitted or estimated to be submitted;
b. A summary demonstrating compliance status with 40 CFR 63 Subpart R including reference to submittal dates or reports made or included;
c. A summary demonstrating compliance status with 40 CFR 63 Subpart CC including reference to submittal dates or reports made or included;
d. A summary demonstrating compliance status with 40 CFR 60 Subpart EEEE including reference to submittal dates or reports made or included;
e. A summary demonstrating compliance status with 40 CFR 60 Subpart QQQ including reference to submittal dates or reports made or included;
f. A summary demonstrating compliance status with 40 CFR 61 Subpart FF including reference to submittal dates or reports made or included.

P. EU15 – COOLING TOWERS

EU15a: North Cooling Tower
EU15b: South Cooling Tower

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
P.1, P.4, P.7, P.12, P.13	PM	TDS of 1500 ppm	Conductivity	Quarterly	Semiannually
P.2, P.5, P.7, P.8, P.10, P.12, P.13	MACT CC - HAPs	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannually and 40 CFR 63 Subpart CC
P.3, P.6, P.9, P.11, P.12, P.13	MACT Q – Chromium Compounds	40 CFR 63 Subpart Q	Recordkeeping / 40 CFR 63 Subpart Q	Ongoing / 40 CFR 63 Subpart Q	Semiannual and 40 CFR 63 Subpart Q

Conditions

P.1. Calumet shall minimize particulate matter emissions from the cooling towers by maintaining the drift eliminators equipped on the cooling towers, and controlling the total dissolved solids in the cooling water. The maximum total dissolved solids of cooling tower water shall not exceed 1,500 parts per million (ARM 17.8.1211, ARM 17.8.752).

P.2. Calumet shall minimize VOC emissions from the cooling towers by complying with the applicable requirements of 40 CFR 63 Subpart CC as applicable to heat exchange systems, as defined in this subpart. This condition is not intended to expand the requirements and applicability of 40 CFR 63 Subpart CC (ARM 17.8.1211, ARM 17.8.752, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

P.3. Calumet shall comply with the requirements of 40 CFR 63 Subpart Q – National Emissions Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers, during any timeframe in which chromium-based water treatment chemicals are used (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart Q).

Compliance Demonstration

P.4. Calumet shall test a representative grab sample of cooling water tower water for conductivity no less than once per calendar quarter utilizing Method 120.1 conductivity test procedures, as found for use under 40 CFR 136, or alternatively, at a more frequent interval and/or with different methods as may be proposed in writing by Calumet and approved in writing by DEQ. The results shall be recorded and compared to the conductivity that would represent the 1,500-ppm total dissolved solids limit in a log. Calumet shall maintain, on-site, documentation regarding the drift rate of drift eliminators maintained on each cooling tower (ARM 17.8.749, ARM 17.8.1213).

P.5. Calumet shall monitor compliance with 40 CFR 63 Subpart CC as required by 40 CFR 63 Subpart CC (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 60 Subpart CC).

P.6. Calumet shall maintain records of cooling tower treatment chemicals to demonstrate no chromium compounds are used, or monitor compliance with 40 CFR 63 Subpart Q as required by 40 CFR 63 Subpart Q (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart Q).

Recordkeeping

P.7. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ, and must be submitted to DEQ upon request (ARM 17.8.1212).

P.8. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

P.9. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart Q (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart Q).

Reporting

P.10. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

P.11. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart Q (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart Q).

P.12. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements.

P.13. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. Summary of information used to monitor compliance with the cooling tower conductivity
b. Summary demonstrating compliance status with 40 CFR 63 Subpart CC

c. Summary demonstrating applicability status and compliance status with 40 CFR 63 Subpart Q

Q. EU16: WASTEWATER TREATMENT

EU16a: Individual drain systems including junction boxes, gauging and sampling devices
EU16b: API Separators
EU16c: Closed Vent Systems and Control Devices
EU16d: External Floating Roof Wastewater Storage Tank 143
EU16e: External Floating Roof Wastewater Storage Tank 145
EU16f: Fixed Roof Wastewater Storage Tank 144A
EU16g: Fixed Roof Wastewater Storage Tank 144B
EU16h: Fixed Roof Wastewater Storage Tank 147
EU16i: Fixed Roof Wastewater Storage Tank 186

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
Q.1, Q.4, Q.7, Q.8, Q.11, Q.14, Q.15	VOC	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	Semiannual and 40 CFR 60 Subpart QQQ
Q.2, Q.5, Q.9, Q.12, Q.14, Q.15	HAPs	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
Q.3, Q.6, Q.10, Q.13, Q.14, Q.15	Benzene	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	40 CFR 61 Subpart FF	Semiannual and 40 CFR 61 Subpart FF

Conditions:

Q.1. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

Q.2. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart CC (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

Q.3. Calumet shall comply with all applicable requirements of 40 CFR 61 Subpart FF (ARM 17.8.1211, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Compliance Demonstration:

Q.4. Calumet shall monitor compliance with 40 CFR 60 Subpart QQQ as required by 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

Q.5. Calumet shall monitor compliance with 40 CFR 63 Subpart CC as required by 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

Q.6. Calumet shall monitor compliance with 40 CFR 61 Subpart FF as required by 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Recordkeeping:

Q.7. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and must be submitted to DEQ upon request (ARM 17.8.1212).

Q.8. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

Q.9. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

Q.10. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Reporting:

Q.11. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

Q.12. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

Q.13. Calumet shall comply with all applicable reporting requirements of 40 CFR 61 Subpart FF (ARM 17.8.1212, ARM 17.8.341, ARM 17.8.302, and 40 CFR 61 Subpart FF).

Q.14. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements.

Q.15. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. A summary demonstrating compliance status with 40 CFR 60 Subpart QQQ including reference to submittal dates of reports made or included;
b. A summary demonstrating compliance status with 40 CFR 63 Subpart CC including reference to submittal dates of reports made or included;
c. A summary demonstrating compliance status with 40 CFR 61 Subpart FF including reference to submittal dates of reports made or included.

R. EU17: BOILERS

EU17a: Boiler #1 and #2
EU17b: Boiler #3

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
R.1, R.2, R.10, R.13, R.22, R.29, R.37, R.38	Boiler #1 and #2 NO_X	76.50 lb/hr and Umbrella Limit	Method 7	Biennial Testing	Semiannual and Section III.A.2
R.1, R.2, R.10, R.14, R.22, R.29, R.37, R.38	Boiler #1 and #2 CO	4.4 TPY 1.00 lb/hr Umbrella Limit	Method 10	Biennial Testing	Semiannual and Section III.A.2
R.2, R.4, R.11, R.12, R.16, R.37, R.38	Boiler #1 and #2 SO_2	148 lb/hr, 1 yr average 174 lb/hr, 24hr average 355 lb/hr, 3hr average	CEMS	Continuous	Semiannual
R.3, R.15, R.22, R.37, R.38	Boiler #3 Capacity	60.5 MMBtu/hr - HHV	Record-keeping	Ongoing	Semiannual
R.3, R.10, R.15, R.22, R.37, R.38	Boiler #3 NO_X	0.019 lb/MMBTU, 3-hr average and Umbrella Limit	Method 7	Annual	Semiannual and Section III.A.2
R.3, R.15, R.37, R.38	Boiler #3 SO2	162 ppmv H_2S on a 3-hr average basis	CEMS	Continuous	Semiannual
R.3, R.10, R.15, R.22, R.37, R.38	Boiler #3 CO	0.034 lb/MMBtu, 3hr averageand Umbrella Limit	Method 10	Biennial	Semiannual
R.3, R.15, R.22, R.37, R.38	Boiler #3 Design	ULNB; flue gas recirculation; fire NG and RFG	Record-keeping	Ongoing	Semiannual
R.4, R.16, R.22, R.37, R.38	Boiler #1 and #2 SWSOH Combustion	Only when SO_2 CEMS operational	Record-keeping	Ongoing	Semiannual
R.5, R.17, R.22, R.24, R.32, R.37, R.38	MACT DDDDD: HAPs	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	Semiannual and 40 CFR 63 Subpart DDDDD
R.6, R.11, A.24, R.18, R.25, R.33, R.37, R.38	Boiler #1 and #2 NSPS J: SO_2	0.10 gr/dscf H_2S in fuel gas, 3-hr rolling average basis	40 CFR 60 Subpart J	40 CFR 60 Subpart J	Quarterly and 40 CFR 60 Subpart J

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Frequency	Reporting Requirements
R.7, R.15, R.26, R.34, R.37, R.38	Boiler #3 NSPS Ja: SO_2	$\underline{H_2S \text{ in fuel gas:}}$ 162 ppmv on a 3-hr rolling average basis, and 60 ppmv on a 365-calendar day rolling average basis	40 CFR 60 Subpart Ja	40 CFR 60 Subpart Ja	Semiannual and 40 CFR 60 Subpart Ja
R.8, R.20, R.27, R.35, R.37, R.38	NSPS QQQ: VOC	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	40 CFR 60 Subpart QQQ	Semiannual and 40 CFR 60 Subpart QQQ
R.9, R.21, R.28, R.36, R.37, R.38	NSPS Dc: SO_2 and PM	40 CFR 60 Subpart Dc	40 CFR 60 Subpart Dc	40 CFR 60 Subpart Dc	Semiannual and 40 CFR 60 Subpart Dc

Conditions:

R.1. Calumet shall comply with the NO_X and CO Umbrella limitations of Section III.B.5 and Section III.B.6.

R.2. Boiler #1 and #2 emissions combined shall not exceed:

a. SO_2 (ARM 17.8.749):

i. Annual: 648 TPY on a rolling 12-month sum basis
ii. Hourly: 148 pounds per hour (lb/hr) averaged over 1 year
iii. 174 lb/hr averaged over a 24-hour period
iv. 355 lb/hr averaged over a 3-hour period

b. NO_X: 76.50 lb/hr (ARM 17.8.752)

c. CO (ARM 17.8.752):

i. Annual 4.4 TPY on a rolling 12-month sum basis
ii. Hourly 1.00 lb/hr

R.3. Boiler #3:

a. The maximum rated capacity of Boiler #3 shall not exceed 60.5 MMBtu/hr on a higher heating value basis (ARM 17.8.749).

b. NO_X emission limit shall be based on the actual performance as demonstrated by the required initial performance test, but shall not exceed 0.019 pounds per million British

thermal units (lb/MMBtu) (1.15 lb/hr) on a 3-hour average basis (Consent Decree, ARM 17.8.752, ARM 17.8.749).

c. Refinery fuel gas combusted in Boiler #3 shall not contain H_2S at a concentration greater than 162 ppmv on a 3-hour rolling average basis (ARM 17.8.52).

d. CO emissions shall not exceed 0.034 lb/MMBtu based on a 3-hour average (ARM 17.8.752).

e. Calumet must install, operate, and maintain an ULNB and flue gas recirculation on Boiler #3 (ARM 17.8.1211, ARM 17.8.752).

f. Boiler #3 shall only combust pipeline quality natural gas or refinery fuel gas (ARM 17.8.1211, ARM 17.8.752).

R.4. When the SO_2/O_2 CEMS is operational on the Boiler #1 and Boiler #2 stack, Calumet may combust Sour Water Stripper Overhead in those boilers. Combustion of the SWSOH and any other refinery fuel gas in Boiler #1 and Boiler #2 shall meet the applicable limitations in 40 CFR 60 Subpart J (Consent Decree, ARM 17.8.749, ARM 17.8.340, ARM 17.8.302 and 40 CFR 60 Subpart J).

R.5. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart DDDDD, including as applicable to the #1, #2, and #3 Boilers (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

R.6. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart J, including as applicable to the #1 and #2 Boilers (ARM 17.8.1211, Consent Decree, ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart J).

R.7. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart Ja, including as applicable to the #3 Boiler (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

R.8. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart QQQ, including as applicable to the individual drain system (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

R.9. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart Dc, including as applicable to Boiler #3 (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Dc).

Compliance Demonstration:

R.10. Calumet shall utilize an emissions factor as derived from the last source test completed as required in below conditions, and fuel usage, to determine mass emissions of NO_X and CO

emissions from Boilers #1, #2, and #3 against the NO_X and CO Umbrella Limitation. (ARM 17.8.1213).

R.11. By July 1, 2008, Calumet shall install and operate an SO_2 and O_2 CEMS and a volumetric flow rate monitor on the stack for the #1 and #2 Boilers, to be used as the primary analytical instrument to determine compliance with state and federal SO_2 requirements. By July 1, 2008, Calumet shall initially certify the #1 and #2 Boiler SO_2/O_2 CEMS and the volumetric flow rate monitor in accordance with 40 CFR Part 60, Performance Specifications 2 and 3 and 6. After initial certification, Calumet shall conduct annual Relative Accuracy Test Audits (RATA) of the #1 and #2 Boiler SO_2/O_2 CEMS, and volumetric flow rate monitoring conformance with 40 CFR 60, Appendix F. After initial certification, Calumet shall also continue to implement all of the requirements of 40 CFR 60.13 and 40 CFR 60, Appendices B and F for the #1 and #2 Boilers SO_2/O_2 CEMS and flow rate monitor (May 2008 Administrative Order on Consent and ARM 17.8.749).

R.12. In the event that the SO_2/O_2 CEMS or stack volumetric flow rate monitor is not operational, Calumet must (ARM 17.8.749):

a. notify DEQ of the problem within 24 hours (by phone) followed by written notification within 7 days;

b. continue to monitor using the H_2S CEMS at the fuel gas drum (pre-combustion);

c. route all SWSOH to the flare system caustic scrubber;

d. repair and/or replace the SO_2/O_2 CEMS equipment and continue to monitor compliance as required in Section III.R.11; and

e. notify DEQ within 24-hours when the SO_2/O_2 CEMS is back on-line.

R.13. Biennially, Calumet shall test the #1 and #2 Boiler for NO_X. Such testing shall occur while sending all Sour Water Stripper Overhead to Boiler #1 and #2. The actual fuel burning rates and the emission factors developed from the most recent compliance source test shall be used to monitor compliance with Section III.R.1 as well as the NO_X Umbrella Limit. Testing shall occur concurrently with CO testing (ARM 17.8.1213, ARM 17.8.105, ARM 17.8.106).

R.14. Compliance with the #1 and #2 Boiler CO emission limits shall be determined through biennial compliance source testing concurrent with NO_X testing and by using the actual fuel burning rates and the emission factors developed from the most recent compliance source test (ARM 17.8.749).

R.15. Boiler #3 compliance shall be monitored as follows:

a. Compliance with the Boiler #3 refinery fuel gas H_2S limitations shall be based on the data from the H_2S CEMS at the fuel gas drum (pre-combustion), which must comply with 40 CFR 60 Subpart Ja refinery fuel gas H_2S CEMS requirements (ARM 17.8.340, 40 CFR 60 Subpart Ja, and ARM 17.8.749).

b. Once every calendar year, Calumet shall test Boiler #3 for NO_X emissions. The test shall include tracking the amount of fuel burned during the test, and testing of the fuel burned during the test, to report emissions on a lb/MMBtu basis as well as a lb/hr basis (ARM 17.8.1213).

c. Compliance with the Boiler #3 CO emission limits shall be demonstrated through compliance source testing and by using the actual fuel burning rates and the emission factors developed from the most recent compliance source test (ARM 17.8.749). Testing shall occur concurrently with NOX testing (ARM 17.8.1213, ARM 17.8.105, ARM 17.8.106).

d. Calumet shall maintain records of the MMBtu/hr burned by hour (ARM 17.8.1213).

R.16. Calumet shall, during any time that any Boiler SO_2 CEMS are experiencing downtime, note the operational status of the sour water stripper and how overhead is handled during that timeframe (ARM 17.8.1213).

R.17. Calumet shall monitor compliance with 40 CFR 63 Subpart DDDDD as required by 40 CFR 63 Subpart DDDDD (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

R.18. Calumet shall monitor compliance with 40 CFR 60 Subpart J as required by 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart J).

R.19. Calumet shall monitor compliance with 40 CFR 60 Subpart Ja as required by 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

R.20. Calumet shall monitor compliance with 40 CFR 60 Subpart QQQ as required by 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

R.21. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart Dc (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Dc).

Recordkeeping:

R.22. Calumet shall comply with the NO_X and CO Umbrella limit recordkeeping requirements of Section III.B.17 for Boilers #1, #2, and #3 (ARM 17.8.1212).

R.23. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and must be submitted to DEQ upon request (ARM 17.8.1212).

R.24. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

R.25. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart J).

R.26. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

R.27. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

R.28. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart Dc (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Dc).

Reporting:

R.29. Calumet shall comply with the NO_X and CO Umbrella limit reporting requirements of Section III.B.26 for Boilers #1, 2 and 3 (ARM 17.8.1212).

R.30. Boilers #1 and #2:

Calumet shall provide semiannual emission reports which shall include the following (ARM 17.8.749):

a. SO_2 emission estimates for #1 and #2 Boilers, for each month, including:

i. Hourly SO_2 CEMS data for the reporting period;

ii. Fuel gas H_2S analyzer data for the reporting the period;

b. NO_X emission estimates for each month. The NO_X emission rates shall be reported as an hourly average and a monthly total;

c. CO emission estimates for the #1 and #2 Boilers, for each month. The CO emission rate shall be reported as an hourly average;

d. Compliance source test data used to update emission factors, conducted during the reporting period;

e. Calumet shall maintain records of daily fuel usage (in MMscf/yr) in the #1 and # 2 Boilers. The fuel usage shall be reported annually for each Boiler based on a 12-month total (ARM 17.8.749);

f. Identification of any periods of excess emissions or other excursions during the reporting period; and

g. Monitoring downtime that occurred during the reporting period.

R.31. Boiler #3:

Calumet shall provide semiannual emission reports to monitor compliance with Section II.C.4 using data required in Section II.F.3. The semiannual report shall include the following (ARM 17.8.749):

a. SO_2 emission estimates for the Boiler #3, for each month, including:

   Fuel gas H_2S analyzer data;

b. NO_X emission estimates for each month. The NO_X emission rates shall be reported as an hourly average;

c. CO emission estimates for the Boiler #3, for each month. The CO emission rate shall be reported as an hourly average;

d. Compliance source test data used to update emission factors, conducted during the reporting period;

e. Identification of any periods of excess emissions or other excursions during the reporting period; and

f. Monitoring downtime that occurred during the reporting period.

R.32. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart DDDDD).

R.33. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart J).

R.34. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart Ja (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Ja).

R.35. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart QQQ (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart QQQ).

R.36. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart Dc (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Dc).

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

R.38. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. A summary of any source testing that was performed during the reporting period including date testing was performed, result of the test, and date the report was submitted or estimated to be submitted;

b. A summary demonstrating compliance status with 40 CFR 60 Subpart J including reference to submittal dates of reports made or included;

c. A summary demonstrating compliance status with 40 CFR 60 Subpart Ja including reference to submittal dates of reports made or included;

d. A summary demonstrating compliance status with 40 CFR 60 Subpart QQQ including reference to submittal dates of reports made or included;

e. A summary demonstrating compliance status with 40 CFR 60 Subpart Dc including reference to submittal dates of reports made or included;

f. Reference to dates that s reports were submitted

g. Any data indicating an hourly MMBtu/hr rate exceeding 60.5 MMBtu/hr on a HHV basis

h. The records required by Section III.R.16 for the semiannual reporting period.

S. EU18: TANKS

Tank #	Tank Service	MTVP	Size bbls	Roof Type	Constructed /Modified	Comments
1	Jet Fuel Additive	--	152	Fixed	1962	40 CFR 63 Subpart EEEE
2	Propane	--	800	PV	1965	Pressure Vessel
3	Isobutane	--	2,000	PV	1973	Pressure Vessel
4	Butane	--	600	PV	1939	Pressure Vessel
5	Isobutane	--	600	PV	1960	Pressure Vessel
10	Transmix	--	375	Fixed	1944	40 CFR 63 Subpart CC (Group 2)
14	Isobutane	--	1,400	PV	1960	Pressure Vessel
15	Butane	--	1,400	PV	1960	Pressure Vessel
29	Distillate	<0.75	20,600	Fixed	2013	40 CFR 63 Subpart CC (Group 2)
47	Middle Distillates	<0.75	20,500	Fixed	2013	40 CFR 63 Subpart CC (Group 2)
48	Middle Distillates	<0.75	20,500	Fixed	2013	40 CFR 63 Subpart CC (Group 2)
49	Middle Distillates	<0.75	20,500	Fixed	2013	40 CFR 63 Subpart CC (Group 2)
51	Treated Gas Oil	<0.75	21,000	Fixed	2013	40 CFR 63 Subpart CC (Group 2)
52	Gasoline	>0.75	19,000	EFR	2014	40 CFR 60 Subpart Kb; 40 CFR 63 Subpart CC (Group 1)
54	Fire Water	na	18,000	Fixed	2015	Not regulated

Tank #	Tank Service	MTVP	Size bbls	Roof Type	Constructed /Modified	Comments
58	Middle Distillates	<0.75	20,983	Fixed	2022	40 CFR 63 Subpart CC (Group 2)
100	#5 Fuel Oil or NaHS	<0.75	1,100	Fixed	1959	40 CFR 63 Subpart CC (Group 2)
101	#5 Fuel Oil or NaHS	<0.75	1,100	Fixed	1959	40 CFR 63 Subpart CC (Group 2)
116	Distillate	<0.75	44,900	Fixed	1972	40 CFR 63 Subpart CC (Group 2)
118	Asphalt Emulsion	<0.75	2,000	Fixed	1973	40 CFR 63 Subpart CC (Group 2)
119	Asphalt Emulsion	<0.75	2,000	Fixed	1973	40 CFR 63 Subpart CC (Group 2)
120	Asphalt Emulsion	<0.75	2,200	Fixed	1980	40 CFR 63 Subpart CC (Group 2)
121	Asphalt Emulsion	<0.75	2,200	Fixed	1980	40 CFR 63 Subpart CC (Group 2)
122	Gasoline	>0.75	21,900	EFR	2014	40 CFR 60 Subpart Kb; 40 CFR 63 Subpart CC (Group 1)
123	Gasoline	>0.75	21,900	EFR	2014	40 CFR 60 Subpart Kb; 40 CFR 63 Subpart CC (Group 1)
124	Naphtha	>0.75	21,500	EFR	1986	40 CFR 60 Subpart Kb; 40 CFR 63 Subpart CC (Group 1)
125	Distillate / Gas Oil	<0.75	38,500	Fixed	1990	40 CFR 63 Subpart CC (Group 2)
126	Gasoline	>0.75	29,500	EFR	1990	40 CFR 60 Subpart Kb; 40 CFR 63 Subpart CC (Group 1)
127	Gasoline	>0.75	21,500	EFR	1960	40 CFR 63 Subpart CC (Group 1)
128	Raw Diesel	<0.75	21,500	EFR	1960	40 CFR 63 Subpart CC (Group 2)
150	Raw Kerosene	<0.75	30,100	Fixed	2008	40 CFR 63 Subpart CC (Group 2)
170	Distillate	<0.75	10,200	Fixed	2008	40 CFR 63 Subpart CC (Group 2)
171	Distillate	<0.75	10,200	Fixed	2008	40 CFR 63 Subpart CC (Group 2)
175	Ethanol	>0.75	400	Fixed	< 1992	40 CFR 63 Subpart CC (Group 2)
176	Ethanol	>0.75	5,000	IFR	2011	40 CFR 60 Subpart Kb; 40 CFR 63 Subpart CC (Group 2)
201	Crude Oil	>0.75	69,700	EFR	2015	40 CFR 60 Subpart Kb; 40 CFR 63 Subpart CC (Group 1)
202	Crude Oil	>0.75	69,700	EFR	2015	40 CFR 60 Subpart Kb; 40 CFR 63 Subpart CC (Group 1)
203	Crude Oil	>0.75	69,700	EFR	Not Yet Installed	40 CFR 60 Subpart Kb; 40 CFR 63 Subpart CC (Group 1)
Tank Farm Equipment Components						40 CFR 63 Subpart CC (LDAR)
Individual Drain System		40 CFR 60 Subpart QQQ, 40 CFR 63 Subpart CC, 40 CFR 61 Subpart FF				

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
S.1, S.16, S.19, S.20, S.23, S.26, S.27	NSPS Kb - VOC	40 CFR 60 Subpart Kb	40 CFR 60 Subpart Kb	40 CFR 60 Subpart Kb	Semiannual and 40 CFR 60 Subpart Kb
S.2, S.17, S.19, S.21, S.24, S.26, S.27	MACT CC - HAPs	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannual and 40 CFR 63 Subpart CC
S.3, S.18, S.19, S.22, S.25, S.26, S.27	MACT EEEE - HAPs	40 CFR 63 Subpart EEEE	40 CFR 63 Subpart EEEE	40 CFR 63 Subpart EEEE	Semiannual and 40 CFR 63 Subpart EEEE
S.4, S.15, S.19, S.26, S.27	Tank Storage and Design	Tank Storage and Design	Recordkeeping	Ongoing	Semiannual
S.5, S.15, S.19, S.26, S.27	Tank Storage and Design	Tank Storage and Design	Recordkeeping	Ongoing	Semiannual
S.6, S.15, S.19, S.26, S.27	Tank Storage and Design	Tank Storage and Design	Recordkeeping	Ongoing	Semiannual
S.7, S.15, S.19, S.26, S.27	Tank Storage and Design	Tank Storage and Design	Recordkeeping	Ongoing	Semiannual
S.8, S.15, S.19, S.26, S.27	Tank Storage and Design	Tank Storage and Design	Recordkeeping	Ongoing	Semiannual
S.9, S.15, S.19, S.26, S.27	Tank Storage and Design	Tank Storage and Design	Recordkeeping	Ongoing	Semiannual
S.10, S.15, S.19, S.26, S.27	Tank Storage and Design	Tank Storage and Design	Recordkeeping	Ongoing	Semiannual
S.11, S.15, S.19, S.26, S.27	Tank Storage and Design	Tank Storage and Design	Recordkeeping	Ongoing	Semiannual
S.12, S.15, S.19, S.26, S.27	Tank Storage and Design	Tank Storage and Design	Recordkeeping	Ongoing	Semiannual
S.13, S.15, S.19, S.26, S.27	Tank Storage and Design	Tank Storage and Design	Recordkeeping	Ongoing	Semiannual
S.14, S.15, S.19, S.26, S.27	Tank Storage and Design	Tank Storage and Design	Recordkeeping	Ongoing	Semiannual

Conditions:

S.1. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart Kb (ARM 17.8.1211, AMR 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Kb).

S.2. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart CC (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

S.3. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart EEEE (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart EEEE).

S.4. Storage tanks #47, #48, #49, and #58 shall be used to store middle distillates and shall be equipped with fixed roofs. Storage tank #58 shall also be equipped and operated with a submerged fille (ARM 17.8.749 and ARM 17.8.752).

S.5. Storage tanks #50 and #102 shall be equipped with a fixed roof (ARM 17.8.752).

S.6. Storage tanks #100 and #101 shall be used to store #5 Fuel Oil or NaHS and shall be equipped with a fixed roof (ARM 17.8.749).

S.7. Storage tank #52 shall be used to store gasoline and shall be equipped with an external floating roof, a mechanical shoe seal, and a gasketed sliding cover with a pole sleeve and pole wiper on each guidepole (ARM 17.8.752).

S.8. Storage tanks #123, #126 and #127 shall be used to store unleaded gasoline and shall be equipped with an external floating roof and a mechanical shoe seal (ultracheck safe sleeve guide pole) (ARM 17.8.749 and ARM 17.8.752).

S.9. Storage tank #124 shall be used to store Naphtha (ARM 17.8.752).

S.10. Storage tanks #122, #124, #126, #201, #202, and #203 shall be equipped with dual-seal external floating roofs with guide pole sleeves (ARM 17.8.752).

S.11. Storage tanks #125 and #128 shall be maintained in heavy liquids service only, with maximum vapor pressure of contents contained not to exceed 0.5 pounds per square inch absolute (psia). The tanks shall be equipped and operated as a fixed roof tank with pressure/vacuum vent and submerged fill (ARM 17.8.749 and ARM 17.8.752).

S.12. Storage tanks #50, #55, #56, #69, #102, #110, #112, #130, #132, #133, #135, #137, #139, and #140 shall be used for heavy oil (ARM 17.8.749).

S.13. Storage tanks #201, #202, and #203 shall be used for crude oil service (ARM 17.8.749).

S.14. Storage tank #9 shall be used for caustic service (ARM 17.8.749).

Compliance Demonstration:

S.15. Calumet shall maintain records on-site as to tank size, location, identifying number, design, contents/service, and throughput, such that tank service on any one specific day can be identified, compliance with the above requirements can be demonstrated, and emissions from any tank can be determined (ARM 17.8.1213).

S.16. Calumet shall monitor compliance with 40 CFR 60 Subpart Kb as required by 40 CFR 60 Subpart Kb (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Kb).

S.17. Calumet shall monitor compliance with 40 CFR 63 Subpart CC as required by 40 CFR 63 Subpart CC (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

S.18. Calumet shall monitor compliance with 40 CFR 63 Subpart EEEE as required by 40 CFR 63 Subpart EEEE (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart EEEE).

Recordkeeping:

S.19. Calumet shall maintain, under Calumet's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and must be submitted to DEQ upon request (ARM 17.8.1212).

S.20. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart Kb (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Kb).

S.21. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

S.22. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart EEEE (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart EEEE).

Reporting:

S.23. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart Kb (ARM 17.8.1212, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Kb).

S.24. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart CC (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

S.25. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart EEEE (ARM 17.8.1212, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart EEEE).

S.26. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements.

S.27. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide (ARM 17.8.1212(3)):

a. A summary demonstrating compliance status with 40 CFR 60 Subpart Kb including reference to submittal dates of reports made or included;

b. A summary demonstrating compliance status with 40 CFR 63 Subpart CC including reference to submittal dates of reports made or included;

c. A summary of any tank service changes during the semiannual reporting period.

T. EU19– STATIONARY INTERNAL COMBUSTION ENGINES

EU19a – 2011 John Deere 400hp Emergency Generator Engine
EU19b – 2006 Caterpillar 540hp Emergency Air Compressor Engine
EU19c – 2006 Cummins 165hp Emergency API Storm Water Pump
EU19d – 1986 Cummins 240hp Emergency Fire Water Pump
EU19e – 2015 John Deere 300hp Emergency Fire Water Pump
EU19f– 2015 John Deere 300hp Emergency Fire Water Pump

Condition(s)	Pollutant/ Parameter	Permit Limit	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
T.1, T.3, T.5, T.7, T.9, T.10	NSPS IIII	40 CFR 60 Subpart IIII	40 CFR 60 Subpart IIII	40 CFR 60 Subpart IIII	Semiannual and 40 CFR 60 Subpart IIII
T.2, T.4, T.6, T.8, T.9, T.10	MACT ZZZZ	40 CFR 63 Subpart ZZZZ	40 CFR 63 Subpart ZZZZ	40 CFR 63 Subpart ZZZZ	Semiannual and 40 CFR 63 Subpart ZZZZ

Conditions

T.1. Calumet shall comply with all applicable requirements of 40 CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart IIII).

T.2. Calumet shall comply with all applicable requirements of 40 CFR 63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart ZZZZ).

Compliance Demonstration

T.3. Calumet shall demonstrate compliance with 40 CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines as required by 40 CFR 60 Subpart IIII (ARM 17.8.1213, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart IIII).

T.4. Calumet shall demonstrate compliance with 40 CFR 63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines as required by 40 CFR 63 Subpart ZZZZ (ARM 17.8.1213, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart ZZZZ).

Recordkeeping

T.5. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subpart IIII (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart IIII).

T.6. Calumet shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart ZZZZ (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart ZZZZ).

Reporting

T.7. Calumet shall comply with all applicable reporting requirements of 40 CFR 60 Subpart IIII (ARM 17.8.1211, ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart IIII).

T.8. Calumet shall comply with all applicable reporting requirements of 40 CFR 63 Subpart ZZZZ (ARM 17.8.1211, ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart ZZZZ).

T.9. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements.

T.10. The semiannual monitoring report shall clearly identify all deviations from permit requirements and shall provide a summary of compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ (ARM 17.8.1212(3)).

SECTION IV. NON-APPLICABLE REQUIREMENTS

Air Quality Administrative Rules of Montana and Federal Regulations identified by Calumet as not applicable to the facility or to a specific emissions unit at the time of the permit issuance for which DEQ provided a shield are listed below (ARM 17.8.1214).

Citation	Title	Basis
Federal Regulations		
Standard of Performance for New Stationary Sources (NSPS)		
40 CFR 60 Subpart D	Performance Standards for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971	There are no >250 MMBtu/hour steam generating units at the refinery
40 CFR 60 Subpart Da	Performance Standards for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After September 18, 1978.	There are no electric utility steam generating units at the refinery.
40 CFR 60 Subpart Db	Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units	There are no >100 MMBtu/hour steam generating units at the refinery.
40 CFR 60 Subpart GG	Standards of Performance for Stationary Gas Turbines	There are no combustion turbines at the refinery.
40 CFR 60 Subpart III	Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	Refinery does not operate any SOCMI air oxidation unit processes that make a chemical listed in 40 CFR 60.617.
National Emission Standards for Hazardous Air Pollutants (NESHAPS)		
40 CFR 61 Subpart Y	National Emission Standards for Benzene Emissions from Benzene Storage Devices	The refinery does not have the ability to the produce benzene products listed as applicable under Subpart Y §61.270.
40 CFR 61 Subpart BB	National Emission Standards for Benzene Emissions from Benzene Storage Vessels	The refinery does not have this source category.
National Emission Standards for Hazardous Air Pollutants for Source Categories (a.k.a. MACT)		
40 CFR 63 Subpart F	National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry	40 CFR 63 Subpart F §63.100(j) exempts petroleum refining process units.

40 CFR 63 Subpart G	National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater	40 CFR 63 Subpart F §63.100(j) exempts petroleum refining process units.
40 CFR 63 Subpart H	National Emission Standards for Organic Hazardous Air Pollutants from Equipment Leaks	40 CFR 63 Subpart F §63.100(j) exempts petroleum refining process units.
Citation	Title	Basis
40 CFR 63 Subpart I	National Emission Standards for Organic Hazardous Air Pollutants for Certain Processes Subject to the Negotiated Regulation for Equipment Leaks	The refinery is not subject to the Negotiated Regulations for Equipment Leaks.
40 CFR 63 Subpart OO	National Emissions Standards for Tanks	No other portion of the applicable sections of 40 CFR 63 references this section, as required.
40 CFR 63 Subpart QQ	National Emissions Standards for Surface Impoundments	No other portion of the applicable sections of 40 CFR 63 references this section, as required.
40 CFR 63 Subpart RR	National Emission Standards for Individual Drain Systems	No other portion of the applicable sections of 40 CFR 63 references this section, as required.
40 CFR 63 Subpart SS	National Emission Standards for Hazardous Air Pollutants for Closed Vent Systems, Control Devices, Recovery Devices, and Routing to a Fuel Gas System or a Process.	Refinery is not subject to any subpart that references the use of this subpart for air emission.
40 CFR 63 Subpart EEE	National Emission Standards for Hazardous Air Pollutants for Hazardous Waste Incinerators	Refinery does not own or operate a Hazardous Waste Incinerator, Cement Kiln, or Aggregate Kiln.
40 CFR 63 Subpart YYYY	National Emission Standards for Combustion Turbines	There are no combustion turbines at the refinery.

SECTION V. GENERAL PERMIT CONDITIONS

A. Compliance Requirements

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

Duty to Comply

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

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

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

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

Need to Halt or Reduce Activity Not a Defense

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

Duty to Provide Information

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

Credible Evidence

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

B. Certification Requirements

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

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

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

3. Compliance certifications shall include the following:

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

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

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

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

4. All compliance certifications must be submitted to the EPA, as well as to DEQ, at the addresses listed in the Notification Addresses Appendix of this permit.

C. Permit Shield

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1. Unless otherwise provided in this permit, the permittee shall maintain compliance monitoring records that include the following information:
   a. The date, place as defined in the permit, and time of sampling or measurement;

   b. The date(s) analyses were performed;

   c. The company or entity that performed the analyses;

   d. The analytical techniques or methods used;

   e. The results of such analyses; and

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

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

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

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

The permittee shall promptly report deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations, and any corrective actions or preventive measures taken. To be considered prompt, deviations shall be reported to DEQ within the following timeframes (unless otherwise specified in an applicable requirement):

1. For deviations which may result in emissions potentially in violation of permit limitations:

a. An initial phone notification (or faxed or electronic notification) describing the incident within 24 hours (or the next business day) of discovery; and,

b. A follow-up written, faxed, or electronic report within 30 days of discovery of the deviation that describes the probable cause of the reported deviation and any corrective actions or preventative measures taken.

2. For deviations attributable to malfunctions, deviations shall be reported to DEQ in accordance with the malfunction reporting requirements under ARM 17.8.110; and

3. For all other deviations, deviations shall be reported to DEQ via a written, faxed, or electronic report within 90 days of discovery (as determined through routine internal review by the permittee).

Prompt deviation reports do not need to be resubmitted with regular semiannual (or other routine) reports, but may be referenced by the date of submittal.

F. Emergency Provisions

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

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

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

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

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

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

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

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

G. Inspection and Entry

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

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

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

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

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

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

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

H. Fee Payment

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

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

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

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

I. Minor Permit Modifications

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

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

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

J. Changes Not Requiring Permit Revision

ARM 17.8, Subchapter 12, Operating Permit Program §1224(1)-(3), (5)&(6)

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

   a. The proposed changes do not require the permittee to obtain a MAQP under ARM Title 17, Chapter 8, Subchapter 7;

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

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

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

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

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

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

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

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

b. DEQ has not objected to such change;
c. Each proposed change meets all applicable requirements and does not violate any existing permit term or condition; and

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

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

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

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

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

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

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

d. Any other change determined by DEQ to be significant.

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

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

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

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

1. Additional applicable requirements under the FCAA become applicable to the facility when the permit has a remaining term of 3 or more years. Reopening and revision of the permit shall be completed not later than 18 months after promulgation of the applicable requirement. No reopening is required under ARM 17.8.1228(1)(a) if the effective date of

the applicable requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms or conditions have been extended pursuant to ARM 17.8.1220(12) or 17.8.1221(2);

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

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

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

M. Permit Expiration and Renewal

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

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

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

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

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

N. Severability Clause

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

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

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

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

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

2. The permit shield provided for in ARM 17.8.1214 shall not extend to administrative permit amendments.

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

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

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

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

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

The permittee shall comply with ARM 17.8.105.

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

The permittee shall comply with ARM 17.8.106.

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

The permittee shall comply with ARM 17.8.110.

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

The permittee shall comply with ARM 17.8.111.

V. Motor Vehicles

ARM 17.8, Subchapter 3, Emission Standards §325

The permittee shall comply with ARM 17.8.325.

W. Annual Emissions Inventory

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

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

X. Open Burning

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

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

Y. Montana Air Quality Permits

ARM 17.8, Subchapter 7, Permit, Construction and Operation of Air Contaminant Sources §745 and 764

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

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

3. ARM 17.8.745(1) specifies de minimis changes as construction or changed conditions of operation at a facility holding a MAQP issued under Chapter 8 that does not increase the facility's potential to emit by more than 5 tons per year of any pollutant, except:

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

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

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

d. Any construction or improvement project with a PTE more than 5 tons per year may not be artificially split into smaller projects to avoid Montana Air Quality Permitting; or
e. Emission reductions obtained through offsetting within a facility are not included when determining the potential emission increase from construction or changed conditions of operation, unless such reductions are made federally enforceable.

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

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

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

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

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

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

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

CC. Stratospheric Ozone Protection – Recycling and Emission Reductions
40 CFR 82, Subpart F

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

DD. Emergency Episode Plan

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

Each major source emitting 100 tons per year located in a Priority I Air Quality Control Region, shall submit to DEQ a legally enforceable Emergency Episode Action Plan (EEAP) that details how the source will curtail emissions during an air pollutant emergency episode. The industrial

EEAP shall be in accordance with DEQ's EEAP and shall be submitted according to a timetable developed by DEQ, following Priority I reclassification.

EE. Definitions

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

APPENDICES

APPENDIX A INSIGNIFICANT EMISSION UNITS

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

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

List of Insignificant Activities:

The following table of insignificant sources and/or activities was provided by Calumet. Because there are no requirements to update such a list, the emission units and/or activities may change from those specified in the table.

Emissions Unit ID	Description	Associated Unit(s)
IEU 1	Chemical Additive Pots	Crude Unit, Cat Poly Unit, Cat Reformer Unit, Storage Loadout Unit, Utility Unit, Asphalt Polymerization Unit
IEU 2	Chemical Additive Tanks	Hydrogen Unit
IEU 3	Tank 117 – Sodium Hydrosulfide Tank	H_2S Scrubbing
IEU 4	Tank 217 – Off Spec Sodium Hydrosulfide Tank	H_2S Scrubbing
IEU 5	1,042-gallon Diesel Tank	Mobil source diesel fuel tank
IEU 6	11,900 barrel Fixed Roof Ammonia Tank	Tank 160

APPENDIX B DEFINITIONS and ABBREVIATIONS

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

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

(a) Corrects typographical errors;

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

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

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

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

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

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

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

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

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

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

(e) Any standard or other requirement of the acid rain program under Title IV of the FCAA or regulations promulgated thereunder;
(f) Any requirements established pursuant to Section 7661c(b) or Section 7414(a)(3) of the FCAA;

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

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

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

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

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

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

"Department" means the Montana Department of Environmental Quality.

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

"Excess Emissions" means any visible emissions from a stack or source, viewed during the visual surveys, that meets or exceeds 15% opacity (or 30% opacity if associated with a 40% opacity limit) during normal operating conditions.

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

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

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

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

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

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

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

(b) Any term, condition or other requirement contained in any MAQP issued by DEQ under Subchapters 7, 8, 9 and 10 of this chapter that is not federally enforceable;

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

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

"Regulated air pollutant" means the following:

(a) Nitrogen oxides or any volatile organic compounds;

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

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

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

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

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

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

"Responsible official" means one of the following:

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

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

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

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

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

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

Abbreviations:

ARM	Administrative Rules of Montana
ASTM	American Society of Testing Materials
BACT	Best Available Control Technology
Btu	British thermal unit
CEMS	Continuous Emissions Monitoring System
COMS	Continuous Opacity Monitoring System
CFR	Code of Federal Regulations
CMS	Continuous Monitoring System
CO	carbon monoxide
DEQ	Department of Environmental Quality
dscf	dry standard cubic foot
dscfm	dry standard cubic foot per minute
EEAP	Emergency Episode Action Plan
EPA	U.S. Environmental Protection Agency
EPA Method	Test methods contained in 40 CFR 60, Appendix A
EU	emissions unit
FCAA	Federal Clean Air Act
FCCU	Fluid Catalytic Cracking Unit
gr	grains
H_2S	hydrogen sulfide
HAP	hazardous air pollutant
hr	hour
IEU	insignificant emissions unit
MACT	Maximum Achievable Control Technology (40 CFR Part 63)
Method	40 CFR 60, Appendix A, Method
MMBtu	million British thermal units
NESHAP	National Emission Standards for Hazardous Air Pollutants (40 CFR Part 61)
NSPS	New Source Performance Standard (40 CFR Part 60)
NO_x	oxides of nitrogen
NO_2	nitrogen dioxide
O_2	oxygen
OMMP	Operations, Malfunctions, and Maintenance Plan
Pb	lead
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter of 10 microns and less
$PM_{2.5}$	particulate matter with an aerodynamic diameter of 2.5 microns and less
PMA	Polymer Modified Asphalt
ppm	parts per million
ppmvd	parts per millions on a dry volumetric basis
psi	pounds per square inch
RATA	Relative Accuracy Test Audit
scf	standard cubic feet
SIC	Source Industrial Classification
SO_2	sulfur dioxide
SO_x	oxides of sulfur
SWSOH	Sour water stripper overhead
TDS	total dissolved solids

TPD	tons per day
TPY	tons per year
U.S.C.	United States Code
VCU	vapor combustion unit
VE	visible emissions
VOC	volatile organic compound

APPENDIX C NOTIFICATION ADDRESSES

Compliance Notifications:

Montana Department of Environmental Quality
Air, Energy & Mining Division
Air Quality Bureau
P.O. Box 200901
Helena, MT 59620-0901

United States EPA
Enforcement and Compliance Assurance Division
Air Enforcement Branch
US EPA Region VIII, Montana Office
10 West 15th Street, Suite 3200
Helena, MT 59626

Permit Modifications:

Montana Department of Environmental Quality
Air, Energy & Mining Division
Air Quality Bureau
P.O. Box 200901
Helena, MT 59620-0901

Air and Radiation Division
Permit and Monitoring Branch
US EPA Region VIII, 8ARD-PM
1595 Wynkoop Street
Denver, CO 80202-1129

APPENDIX D AIR QUALITY INSPECTOR INFORMATION

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

Direction to Plant: Calumet is located at 1900 10th Street Northeast along the Missouri River in the city of Great Falls, Montana.

Safety Equipment Required: Hardhat, steel-toed shoes/boots, and hearing protection (ear plugs will be provided by Calumet) are required at the facility. A detailed safety manual is available at the site, and a Calumet employee will conduct a safety briefing for any inspector prior to entering the plant area.

Facility Plot Plan: The facility plot plan was submitted as part of the application on May 17, 1995, and an update submitted with the renewal application on June 5, 2006.

APPENDIX E SO_2 Ambient Monitoring

The SO_2 Ambient Monitoring was removed as a requirement from MAQP #2161-37, as well as any reporting requirements associated with the ambient monitoring. It was intended to incorporate the removal of those ambient monitoring conditions within this Title V permit (#OP2161-17) but since they were not in the original Title V application, were not incorporated at this time. The removal of the SO_2 ambient monitoring conditions will be incorporated in the Title V applications currently being processed.

May 10, 2023

Joe Dauner
Calumet Montana Refining, LLC
1900 10th Street Northeast
Great Falls, MT 59404

Sent via email:

Dear Mr. Dauner: joseph.dauner@calumetspecialty.com

Montana Air Quality Permit (MAQP) #2161-39 is deemed final as of May 10, 2023, by DEQ. This permit is for the Great Falls Calumet Montana Refining Petroleum Refinery. All conditions of the Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

Conditions: See attached

For the Department,

Julie A. Merkel
Permitting Services Section Supervisor
Air Quality Bureau
(406) 444-3626

Craig Henrikson, P.E.
Environmental Engineer
Air Quality Bureau
(406) 444-6711

Montana Department of Environmental Quality
Air, Energy & Mining Division
Air Quality Bureau

Montana Air Quality Permit #2161-39

Calumet Montana Refining, LLC
1900 10th Street Northeast
Great Falls, MT 59404

May 10, 2023

MONTANA AIR QUALITY PERMIT

Issued to:	Calumet Montana Refining, LLC 1900 10th Street Northeast Great Falls, MT 59404	MAQP: #2161-39 Application Received: 02/09/2023 Application Deemed Complete: 03/15/2023 Preliminary Determination Issued: 03/21/2023 Department Decision Issued: 04/24/2023 Permit Final: 05/10/2023

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to Calumet Montana Refining, LLC (Calumet) 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*., as amended, for the following:

SECTION I: Permitted Facilities

A. Plant Location

Calumet operates a petroleum refinery located at the NE¼ of Section 1, Township 20 North, Range 3 East, in Cascade County, Montana. The refinery is located along the Missouri River in Great Falls, Montana.

B. Permitted Facility

The major permitted equipment at Calumet includes:

- #1 Crude Unit
- #2 Crude Unit
- Fluid Catalytic Cracking Unit (FCCU)
- Hydrogen Plants #1 and #2
- Catalytic Reformer Unit
- Naphtha Hydrodesulfurization (HDS)
- Diesel HDS
- Catalytic Poly Unit
- Hydrogen Fluoride (HF) Alkylation Unit
- Deisobutanizer Unit
- Sodium Hydrosulfate (NaHS) Unit
- Hydrotreater Unit (HTU)
- Polymer-Modified Asphalt (PMA) Unit
- Storage Tanks (heated asphalt, crude oil, middle distillates, and petroleum products)
- Gasoline Truck Loading with a vapor combustor unit (VCU)
- Gasoline Railcar Loading with a VCU
- Asphalt/Diesel Loading and Crude Oil/Gas Oil Rail Unloading Rack
- Primary Flare #1 and Secondary Flare #2

- Miscellaneous Tanks; Utilities (Boilers (#1, #2 and #3), North and South Cooling Towers, Wastewater Treatment including new Dissolved Air Flotation Unit)
- Catalytic Thermal Oxidizer for Remediation Project

A complete list of permitted equipment for Calumet is contained in Section I.A. of the Permit Analysis.

C. Current Permit Action

The current permit action accomplishes several updates, corrections, and changes as presented below:

On 02/09/2023, the Department received a request to modify MAQP #2161-38 for conditions which were incorporated from an application received on October 21, 2002. These elements were incorporated and issued in MAQP #2161-16 on March 19, 2003, and for each Consent Decree (CD) requirement were referenced for applicability to the CD. Later permitting actions including MAQP #2161-19 issued on August 15, 2007, and MAQP #2161-24 issued on September 25, 2010, also incorporated additional Consent Decree items. The current permitting action requests the removal of the references to the Consent Decree. The requirements of the Consent Decree will be replaced with a standard reference for Montana Air Quality Permits using Administrative Rules of Montana (ARM) 17.8.749 - CONDITIONS FOR ISSUANCE OR DENIAL OF PERMIT. DEQ issued a Preliminary Determination on March 7, 2023, after which DEQ confirmed the required public notice had not occurred. The required public notice has since occurred, and the full 15-day comment period associated with this posting will occur. The application also requests several minor corrections to permit conditions issued in recently permitted actions.

SECTION II: Limitations and Conditions

A. General Facility Conditions

1. Calumet 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 shall apply to all equipment or facilities subject to an NSPS Subpart as listed below.

   b. Subpart Dc – Standards of Performance for Small Industrial–Commercial Institutional Steam Generating Units for which construction, modification, or reconstruction is commenced after June 9, 1989. This Subpart applies to Boiler #3, Hot Oil Heater H-1903, and Hot Oil Heater H-1904.

c. Subpart J – Standards of Performance for Petroleum Refineries applies to all fuel gas combustion devices with the exception of those subject to 40 CFR 60 Subpart Ja, in which case 40 CFR 60 Subpart Ja applies.

1. FCCU regenerator: for carbon monoxide (CO) and sulfur dioxide (SO_2) (ARM 17.8.749).

2. Heaters and boilers (ARM 17.8.749).

d. Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced after May 14, 2007 (H-2101, H-2102, H-4101, H-4102, H-3815A, H-3815B, Boiler #3, flare system, fuel gas treatment unit (FGT), sour water stripper (SWS), Hot Oil Heater H-1903, and Hot Oil Heater H-1904). Once the Department of Environmental Quality (DEQ) receives written notification that H-4101, H-4102, H-3815A and H-3815B have been transferred to MRI, the sources will no longer be regulated by this condition.

e. 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.

f. Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture shall apply to all asphalt storage tanks that processes and stores only non-roofing asphalts and was constructed or modified since May 26, 1981. Following replacement as part of the Asphalt Upgrades Project, Tank #55 will be subject to the opacity requirements under Subpart UU.

g. Subpart VV – Standards of Performance for Equipment Leaks of Volatile Organic Compounds (VOC) in the Synthetic Organic Chemicals Manufacturing Industry, shall apply to this refinery as required by 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC.

h. Subpart VVa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.

i. Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries shall apply to the NaHS Unit, HTU, Hydrogen Plant #1, and any other equipment as appropriate. A monitoring and maintenance program as described under 40 CFR 60, Subpart VV shall be instituted. Once DEQ receives written notification that the HTU has been modified, the source will no longer be regulated by this condition.

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. Unless Calumet demonstrates exemption from this standard, the standard applies to compressors, valves, pumps, pressure relief devices, sampling connection system, open-ended valves and lines, flanges, and connectors that are part of the Low Sulfur Fuels expansion project. The piping components within the PMA Unit will be subject to Subpart GGGa following the Asphalt Upgrades Project. The piping components within the HTU will be subject to Subpart GGGa following the Refinery Reconfiguration Project.

k. Subpart QQQ – Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply to the refinery's, individual drains, junction boxes, and oil-water separators.

2. Calumet shall comply with all applicable requirements of ARM 17.8.341, as specified by 40 CFR Part 61, National Emissions Standards for Hazardous Air Pollutants:

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

b. Subpart FF – National Emission Standard for Benzene Waste Operations.

3. Calumet shall comply with all applicable requirements of ARM 17.8.342, as specified by 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants (NESHAP) for Source Categories:

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

b. Subpart Q – NESHAP for Industrial Process Cooling Towers shall apply if Calumet uses chromium-based water treatment chemicals in the cooling tower water.

c. Subpart R – NESHAP for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), as specified under Subpart CC.

d. Subpart CC – NESHAP from Petroleum Refineries shall apply to, but not be limited to, the bulk loading racks (including the gasoline truck loading and railcar loading racks), certain valves and pumps in the alkylation unit, miscellaneous process vents, storage vessels, wastewater, and equipment leaks. The gasoline loading rack provisions in Subpart CC require compliance with applicable Subpart R provisions, and the equipment leak provision requires compliance with applicable 40 CFR 60, Subpart VV provisions.

e. Subpart UUU – NESHAP from Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, shall apply to, but not be limited to, the FCCU and the Catalytic Reformer Unit.

f. Subpart EEEE – NESHAP for Organic Liquids Distribution (Non-Gasoline) shall apply to, but not be limited to, Tank # 1 – diethylene glycol monoether (DEGME) and the naphtha loading rack.

g. Subpart FFFF – NESHAP for Miscellaneous Organic Chemical Manufacturing shall apply to, but not be limited to, miscellaneous organic chemical manufacturing process units (MCPU) which includes the facility-wide collection of MCPU and heat exchange systems, wastewater, and waste management units associated with the same MCPU. The piping fugitive components, wastewater components, and transfer racks at the refinery that are used to load renewable products produced by the MRI RDU shall comply with the applicable Subpart FFFF requirements. An affected source is new if construction or reconstruction of the source commenced after April 4, 2002.

h. Subpart DDDDD – NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters shall apply to, but not be limited to, all boilers and process heaters. This will now include the HTU Fractionation Heater (Hot Oil Heater H-1903, and Hot Oil Heater H-1904.

B. CD Required Language and Emission Credit Generation

1. General Prohibition: Calumet shall not generate or use any NO_X, SO_2, PM, VOC, or CO emissions reductions that result from any projects conducted or controls required pursuant to the Consent Decree (Civ. No. 01-1422LH) as netting reductions or emissions offsets in any PSD, major non-attainment and/or minor New Source Review ("NSR") permit or permit proceeding. Exception to the General Prohibition: Notwithstanding the general prohibition set forth above, Calumet may use 10 tons per year of NO_X and 20 tons per year of SO_2 from the CD Emissions Reductions as credits or offsets in any PSD, major non-attainment and/or minor NSR permit or permit proceeding occurring after March 2002, provided that the new or modified emissions unit: (1) is being constructed or modified for purposes of compliance with Tier 2 gasoline or low sulfur diesel requirements; and (2) already has emissions limits at the time of permitting as follows.

   a. For heaters and boilers, a limit of 0.020 pounds NO_X per million British thermal units (Btu) or less on a 3-hour rolling average basis;

   b. For heaters and boilers, a limit of 0.10 grains of hydrogen sulfide per dry standard cubic foot of fuel gas or 20 ppmvd SO_2 corrected to 0% O_2 both on a 3-hour rolling average;

c. For heaters and boilers, no liquid or solid fuel firing capabilities;

d. For FCCUs, a limit of 20 ppmvd NO_X corrected to 0% O_2 or less on a 365-day rolling average basis;

e. For FCCUs, a limit of 25 ppmvd SO_2 corrected to 0% O_2 or less on a 365-day rolling average basis; and

f. For SRPs, NSPS Subpart J emission limits.

2. Conditions Precedent to Utilization of the exception to the general prohibition against the generation or utilization of CD Emissions Reductions set forth above is subject to the following conditions:

a. Under no circumstances shall Calumet use CD Emissions Reductions for netting and/or offsets prior to the time that actual CD Emissions Reductions have occurred;

b. CD Emissions Reductions may be used only at the Calumet refinery;

c. The CD Emissions Reductions provisions of the CD are for purposes of the CD only and Calumet may not use CD Emissions Reductions for any purpose, including in any subsequent permitting or enforcement proceeding, except as provided herein; and

d. Calumet still shall be subject to all federal and state regulations applicable to the PSD, major non-attainment and/or minor NSR permitting process.

3. Definitions

"CEMS" shall mean continuous emissions monitoring system.

"Fuel Oil" shall mean any liquid fossil fuel with sulfur content of greater than 0.05% by weight.

"Shutdown" shall mean the cessation of operation of equipment for any purpose.

"Startup" shall mean the setting in operation of equipment for any purpose.

"Torch Oil" shall mean FCCU feedstock or light cycle oil that is combusted in the FCC regenerator to assist in starting up or restarting the FCCU.

C. Emission Control Requirements

Calumet shall install, operate, and maintain the following equipment and practices as specified:

1. Flare #1 (primary flare) shall be equipped with a flare gas scrubber (ARM 17.8.749 and ARM 17.8.752).

2. Flare #2 (secondary flare) must maintain a water seal except during periods of startup, shutdown, or malfunction as defined in this permit. These periods of startup, shutdown, and malfunction shall not exceed 9 hours per year based on a 12-month rolling average (ARM 17.8.749).

3. Hydrogen plant reformer heaters shall only be fired with commercially available natural gas, which may include recycled gas from the hydrogen plants, and shall not be fired with refinery fuel gas or refinery Liquefied Petroleum Gas (LPG). The HTU Heater (H-1701) shall be fired with only purchased natural gas or refinery fuel gas that meets 40 CFR 60, Subpart J or Ja requirements. The purge (vent) gas used as fuel in the hydrogen plant reformer heaters shall be sulfur-free (ARM 17.8.752).

4. Hydrogen Plant #3 must be equipped with ULNB and the total combined capacity of the two heaters (H-3815A and H-3815B) shall not exceed 134 MMBtu/hr. Once DEQ receives written notification that H-3815A and H-3815B have been transferred to MRI, the sources will no longer be regulated by this condition (ARM 17.8.752).

5. All process heaters in the #2 Crude Unit (H-2101, H-2102) and the MHC (H-4101, H-4102) shall be equipped with ULNB. Once DEQ receives written notification that H-4101 and H-4102 have been transferred to MRI, the sources will no longer be regulated by this condition (ARM 17.8.749 and ARM 17.8.752).

6. Storage Tanks

    a. Storage tanks #47, #48, and #49 shall be used to store middle distillates with a vapor pressure equal to or less than kerosene/Jet A and shall be equipped with fixed roofs (ARM 17.8.749 and ARM 17.8.752).

    b. Storage tanks #50 and #102 shall be equipped with a fixed roof. Once DEQ receives written notification that tanks #50 and #102 have been transferred to MRI, the sources will no longer be regulated by this condition (ARM 17.8.752).

    c. Storage tanks #100 and #101 shall be used to store #5 Fuel Oil or NaHS and shall be equipped with a fixed roof (ARM 17.8.749).

    d. Storage tank #52 shall be used to store gasoline and shall be equipped with an external floating roof, mechanical shoe seal, and a gasketed sliding cover with a pole sleeve and pole wiper on each guide pole (ARM 17.8.752).

e. Storage tanks #123, #126 and #127 shall be used to store unleaded gasoline and shall be equipped with an external floating roof and a mechanical shoe seal (ultracheck safe sleeve guide pole) (ARM 17.8.749 and ARM 17.8.752).

f. Storage tank #124 shall be used to store Naphtha (ARM 17.8.749).

g. Storage tanks #122, #124, #126, #145B, #201, #202, and #203 shall be equipped with dual-seal external floating roofs with guide pole sleeves (ARM 17.8.752).

h. Storage tanks #125 and #128 shall be maintained in heavy liquids service only, with maximum vapor pressure of contents contained not to exceed 0.5 pounds per square inch absolute (psia). The tanks shall be equipped and operated as a fixed roof tank with pressure/vacuum vent and submerged fill. Once DEQ receives written notification that tank #128 has been transferred to MRI, tank #128 will no longer be regulated by this condition. (ARM 17.8.749 and ARM 17.8.752).

i. Storage tanks #50, #55, #56, #69, #102, #110, #112, #130, #132, #133, #135, #137, #138, #139, and #140 shall be used for heavy oil or asphalt. Once DEQ receives written notification that tanks #50, #102, #112, and #140 have been transferred to MRI, the sources will no longer be regulated by this condition (ARM 17.8.749).

j. Storage tanks #201, #202, and #203 shall be used for crude oil service (ARM 17.8.749).

k. Storage tanks #8 and #9 shall be used for caustic service (ARM 17.8.749).

l. Storage tank #58 shall be used for middle distillates and shall be equipped and operated with a fixed roof and a submerged fill (ARM 17.8.752).

m. Asphalt tank heater #140 shall burn only natural gas or refinery fuel gas in compliance with 40 CFR 60, Subpart J. Once DEQ receives written notification that tank #140 has been transferred to MRI, the source will no longer be regulated by this condition (ARM 17.8.749and 40 CFR 60, Subpart J).

n. Asphalt tank heater #160 shall burn only natural gas or refinery fuel gas in compliance with 40 CFR 60 Subpart Ja (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60, Subpart Ja).

o. Hot Oil Heater (H-1903) and Hot Oil Heater (H-1904) shall burn only natural gas that complies with 40 CFR 60 Subpart Ja (ARM 17.8.752 and 40 CFR 60 Subpart Ja).

p. Calumet shall not cause to be discharged into the atmosphere from any asphalt tank constructed or modified since May 26, 1981, exhaust gases with opacity greater than 0% except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for clearing (ARM 17.8.340 and 40 CFR 60, Subpart UU).

q. For any asphalt tank constructed between November 23, 1968, and May 26, 1981, or any other tank constructed since November 23, 1968, Calumet shall not cause to be discharged into the atmosphere exhaust gases with an opacity of 20% or greater, averaged over 6 consecutive minutes (ARM 17.8.304).

r. For any tank constructed prior to November 23, 1968, Calumet shall not cause to be discharged into the atmosphere exhaust gases with an opacity of 40% or greater, averaged over 6 consecutive minutes (ARM 17.8.304).

s. Tanks and process vessels #55, #130, #132, #133, D-1901 and D-1907 shall utilize a carbon adsorption device on the vent to atmosphere for VOC control (ARM 17.8.752).

t. Hot Oil Heaters H-1903 and H-1904 shall meet the following emission control requirements:

1. Install and operate ULNB for NO_X control (ARM 17.8.752).

2. CO emissions shall not exceed 0.04 lb/MMBtu (HHV), based on a 1-hour average (ARM 17.8.752).

3. Meet work practice standards under 40 CFR 63, Subpart DDDDD (ARM 17.8.749 and 40 CFR 63, Subpart DDDDD).

7. Pressure Vessels – All pressure vessels in HF Acid service, except storage tanks, shall be vented to the flare system (ARM 17.8.749 and ARM 17.8.752).

8. The HF Alkylation Unit shall be operated and maintained as follows (ARM 17.8.749 and ARM 17.8.752):

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

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

c. All pumps used in the alkylation plant shall be fitted with the highest quality state-of-the-art mechanical seals.

d. All pumps shall be monitored and maintained as described in 40 CFR 60.482-2 and all control valves shall be monitored and maintained as described in 40 CFR 60.482-7. All other potential sources of VOC leaks shall be inspected quarterly for evidence of leakage by visual or other detection methods. Repairs shall be made promptly as described in 40 CFR 482-7(d). Records of monitoring and maintenance shall be maintained on site for a minimum of 2 years.

e. All process drains shall consist of water seal traps with covers.

f. All equipment shall be operated and maintained as described in 40 CFR 60.692-2, 60.692-6, and 60.693-1. Inspection reports shall be made available for inspection upon request.

g. The Alkylation Unit process heater shall burn only natural gas or fuel gas in compliance with 40 CFR 60, Subpart J (ARM 17.8.749 and 40 CFR 60, Subpart J).

9. The PMA Unit shall be operated and maintained as follows:

a. All open-ended valves shall have plugs or caps installed on the open end (ARM 17.8.752).

b. All pumps in the PMA unit shall be equipped with standard single seals (ARM 17.8.752).

c. The PMA Unit Polymer Handling Operations shall be equipped with partial or full enclosures at automated transfer points (ARM 17.8.752).

d. The PMA Unit Prilled Sulfur Handling Operations shall be equipped with full enclosures at automated transfer points (ARM 17.8.752).

e. PMA Unit piping fugitive components which are in VOC service will be required to comply with 40 CFR 60, Subpart GGGa and the equipment leak provisions found in 40 CFR 60.482-la through 60.482-10a. PMA Unit piping fugitive components which are in Organic HAP service will be required to comply with the existing source equipment leak provisions found in 40 CFR 63.648 through 649 of 40 CFR 63, Subpart CC. (ARM 17.8.752, ARM 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC).

10. Calumet shall ensure that the NaHS Unit, HTU, Hydrogen Plant #1, and any other equipment as appropriate, comply with the applicable requirements in 40 CFR 63 Subpart GGG and Subpart GGGa, including (ARM 17.8.342, 40 CFR 63 Subpart GGG and Subpart GGGa):

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

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

c. A monitoring and maintenance program as described under 40 CFR 60, Subpart VV shall be instituted.

11. Calumet shall ensure that all process drains consist of water seal traps with covers for the HTU, Hydrogen Units, and any other equipment as appropriate (ARM 17.8.342 and 40 CFR 63 Subpart QQQ).

12. North Cooling Tower and South Cooling Tower

a. Calumet shall minimize particulate matter emissions from the cooling towers by maintaining the drift eliminators equipped on the cooling towers and controlling the total dissolved solids in the cooling water. The maximum total dissolved solids of cooling tower water shall not exceed 1,500 parts per million (ARM 17.8.752).

b. Calumet shall minimize VOC emissions from the cooling towers by complying with the applicable requirements of 40 CFR 63 Subpart CC as applicable to heat exchange systems, as defined in this subpart. This condition is not intended to expand the requirements and applicability of 40 CFR 63 Subpart CC (ARM 17.8.752, ARM 17.8.302, ARM 17.8.342, and 40 CFR 63 Subpart CC).

c. Calumet shall comply with 40 CFR 63 Subpart Q, during any timeframe in which 40 CFR 63 Subpart Q is applicable (ARM 17.8.749, ARM 17.8.302, ARM 17.8.342 and 40 CFR 63 Subpart Q).

13. Calumet must install, operate, and maintain an ULNB and flue gas recirculation (FGR) on Boiler #3 (ARM 17.8.752).

14. Boiler #3 shall only combust pipeline quality natural gas or refinery fuel gas with no SWS overhead gas. SWS overhead gas is considered refinery fuel gas and shall not be burned in Boiler #3 (ARM 17.8.749 and ARM 17.8.752).

15. When the SO_2/O_2 Continuous Emissions Monitoring System (CEMS) is operational on the boiler #1 and Boiler #2 stack, Calumet may combust SWS overhead in Boiler #1 and Boiler #2. Combustion of the SWS overhead and any other refinery fuel gas shall meet the applicable limitations in 40 CFR 60 Subpart J (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60 Subpart J).

16. The gasoline and distillates truck loading rack shall be operated and maintained as follows:

a. Calumet's tank truck loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from cargo tanks during gasoline product loading (ARM 17.8.342).

b. Calumet collected vapors shall be routed to the vapor combustion unit (VCU) at all times. In the event the VCU is inoperable, Calumet may continue to load 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).

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

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

e. The vapor collection system shall be designed to prevent any VOC vapors collected at one loading position from passing to another loading position (ARM 17.8.342).

f. Loadings of liquid products into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks, using the following procedures (ARM 17.8.342):

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

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

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

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

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

A. The gasoline cargo tank meets the applicable test requirements in 40 CFR 63.425(e) to this permit;

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

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

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

g. Calumet shall ensure that loadings of gasoline cargo tanks at the truck loading rack are made only into cargo tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system (ARM 17.8.342).

h. Calumet shall ensure that the terminal and the cargo tank vapor recovery systems are connected during each loading of a gasoline cargo tank at the truck loading rack (ARM 17.8.342).

i. Calumet shall monitor and maintain all pumps, shutoff valves, relief valves, and other piping and valves associated with the gasoline loading rack as described in 40 CFR 60.482-1 through 60.482-10.

j. The truck loading rack VCU stack shall be at least 35 feet above grade (ARM 17.8.749).

17. The East railcar loading rack and VCU shall be operated and maintained as follows when loading gasoline and naphtha:

a. Calumet's gasoline railcar loading rack shall be equipped with a vapor recovery system designed to collect the organic compounds displaced from railcars during gasoline and naphtha loading and vent those emissions to the VCU (ARM 17.8.342 and 40 CFR 63, Subpart CC and ARM 17.8.752).

b. Calumet shall operate and maintain the VCU to control VOC and hazardous air pollutant (HAP) emissions during the loading of gasoline or naphtha in the gasoline railcar loading rack. Calumet's collected vapors shall be routed to the VCU at all times (ARM 17.8.752).

c. The vapor recovery system shall be designed to prevent any VOC vapors collected at one loading position from passing to another loading position (ARM 17.8.749).

d. Loading of gasoline and naphtha railcars shall be restricted to the use of submerged fill and dedicated normal service (ARM 17.8.752).

e. Calumet shall ensure that loading of gasoline and naphtha into railcars at the gasoline railcar loading rack are made only into railcars equipped with vapor recovery equipment that is compatible with the terminal's vapor recovery system (ARM 17.8.749).

f. Loadings of gasoline into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks, using procedures as listed in 40 CFR 63, Subpart R (ARM 17.8.342 and 40 CFR 63, Subpart CC, and ARM 17.8.752).

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

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

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

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

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

A. The gasoline cargo tank meets the applicable test requirements in 40 CFR 63.425(e) to this permit;

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

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

2. After repair work is performed on the cargo tank, before or during the tests in 40 CFR

63.425(g) or (h), subsequently passes, the annual certification test described in 40 CFR 63.425(e).

g. Calumet shall ensure that the terminal's and the railcar's vapor recovery systems are connected during each loading of gasoline and naphtha into railcar at the gasoline railcar loading rack (ARM 17.8.749).

h. The vapor recovery and liquid loading equipment shall be designed and operated to prevent gauge pressure in the gasoline railcar from exceeding 4,500 Pa (450 mm of water) during gasoline loading. This level shall not be exceeded when measured by the procedures specified in 40 CFR 60.503(d) (ARM 17.8.342 and 40 CFR 63, Subpart CC).

i. No pressure-vacuum vent in the permitted terminal's vapor recovery system shall begin to open at a system pressure less than 4,500 Pa (450 mm of water) (ARM 17.8.749).

j. Calumet shall comply with the applicable provisions of 40 CFR 60, Subpart VV, including Calumet shall monitor and maintain all pumps, shutoff valves, relief valves, and other piping and valves associated with the gasoline loading rack as described in 40 CFR 60.482-1 through 60.482-10 (ARM 17.8.749, ARM 17.8.342 and 40 CFR 63, Subpart CC).

k. The gasoline railcar loading rack VCU stack exhaust exit shall be at least 30 feet above grade (ARM 17.8.749).

18. Calumet shall not combust any fuel gas with a hydrogen sulfide (H_2S) concentration in excess of 230 milligram per dry standard cubic meter (mg/dscm) equivalent to 0.10 grains per dry standard cubic foot (gr/dscf) in any applicable fuel gas combustion device (ARM 17.8.340 and 40 CFR 60, Subpart J).

19. For fuel gas combustion devices where construction, reconstruction, or modification commenced after May 14, 2007, Calumet shall not burn any fuel gas that contains H_2S in excess of 162 parts per million volume, dry basis (ppmvd) determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmvd determined daily on a 365-successive calendar day rolling average basis (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60 Subpart Ja).

20. Calumet shall not combust fuel oil as defined in this permit, in any combustion unit, except torch oil as defined in this permit may be used in the FCCU Regenerator during FCCU startups (ARM 17.8.749)

21. The #1 crude unit's stack height shall be at least 150 feet above ground level (ARM 17.8.749).

22. VOC from the dual phase extraction wells and subsequent vapor/liquid separator associated with the AOC-16 remediation project shall be collected and oxidized via an electric catalytic thermal oxidizer designed for 99% destruction efficiency of VOC and HAP during normal operation (ARM 17.8.752).

D. Emission Limitations

1. Plant-wide refinery emissions shall not exceed (ARM 17.8.749):

a. SO_2:

Annual	1,515 tons per year (TPY) on a rolling 12-month sum basis
Daily	4.15 tons/rolling 24-hours

b. CO:

Annual	4,700 TPY on a rolling 12-month sum basis
Daily	12.9 tons/rolling 24-hours

2. Boiler #1 and #2 emissions shall not exceed:

a. SO_2 (ARM 17.8.749):

i. Annual: 648 TPY on a rolling 12-month sum basis
ii. Hourly: 148 pounds per hour (lb/hr) averaged over 1 year
iii. 174 lb/hr averaged over a 24-hour period
iv. 355 lb/hr averaged over a 3-hour period

b. Oxides of Nitrogen (NO_X): 76.50 lb/hr (ARM 17.8.752)

c. CO (ARM 17.8.752):

i. Annual 4.4 TPY on a rolling 12-month sum basis
ii. Hourly 1.00 lb/hr

d. Opacity from Boilers #1 and #2 shall not exceed 40% averaged over any 6 consecutive minutes (ARM 17.8.304).

3. Boiler #3 emissions:

a. The maximum rated capacity of Boiler #3 shall not exceed 60.5 MMBtu/hr on a higher heating value basis (ARM 17.8.749).

b. Opacity from the Boiler #3 shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

c. NO_X emissions shall not exceed 0.019 pounds per million British thermal units (lb/MMBtu) (1.15 lb/hr) on a 3-hour average basis (ARM 17.8.752 and ARM 17.8.749).

d. Refinery fuel gas combusted in Boiler #3 shall not contain H_2S at a concentration greater than 162 ppmv on a 3-hour rolling average basis (ARM 17.8.752).

e. CO emissions shall not exceed 0.034 lb/MMBtu based on a 3-hour average (ARM 17.8.752).

4. HTU Heater (H-1701)

a. The HTU Heater firing rate shall not exceed 22.5 MMBtu/hr on a HHV, 365-day average basis, averaged daily (ARM 17.8.749).

b. NO_X emissions shall not exceed the limit of 0.07 lb/MMBtu (ARM 17.8.752), and 6.9 TPY (ARM 17.8.749).

c. CO emissions shall not exceed the limit of 0.88 lb/hr or 3.84 TPY (ARM 17.8.752).

d. Opacity shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

5. Naphtha Splitter Reboiler (H-0405)

a. The firing rate of the Naphtha Splitter Reboiler H-0405 shall not exceed 9.9 MMBtu/hr on a HHV, 365 day rolling average basis, averaged daily (ARM 17.8.749).

b. NO_X emissions shall not exceed 0.03 lb/MMBtu on a HHV basis (ARM 17.8.749).

6. Naphtha HDS Heater (H-0402a)

a. The firing rate of the Naphtha HDS Heater H-0402a shall not exceed 13.6 MMBtu/hr on a HHV, 365 day rolling average basis, averaged daily (ARM 17.8.749).

b. NO_X emissions shall not exceed 0.03 lb/MMBtu on a HHV basis (ARM 17.8.749).

7. Reformer Heater (H-0403)

a. The firing rate of the Reformer Heater H-0403 shall not exceed 24.2 MMBtu/hr on a HHV, 365 day rolling average basis, averaged daily (ARM 17.8.749).

b. NO_X emissions shall not exceed 0.098 lb/MMBtu on an HHV basis (ARM 17.8.749).

8. Hydrogen Plant #1 Reformer Furnace Stack

a. NO_X emissions shall not exceed the limit of 0.07 lb/MMBtu, 1.90 lb/hr, or 8.3 TPY (ARM 17.8.752).

b. CO emissions shall not exceed the limit of 0.93 lb/hr or 4.1 TPY (ARM 17.8.752).

c. Opacity shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

9. Hydrogen Plant #2

a. NO_X emissions shall not exceed 0.033 lb/MMBtu based on the higher heating value (HHV) (ARM 17.8.752 and ARM 17.8.749), and 11.56 TPY on a rolling 12-month sum (ARM 17.8.749).

b. Opacity shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

10. Hydrogen Plant #3 (Reformer Heaters H-3815A and H-3815B). Once DEQ receives written notification that H-3815A and H-3815B have been transferred to MRI, the sources will no longer be regulated by this condition.

a. The maximum rated capacity of the Hydrogen Plant #3 Reformer Heaters H-3815A and H-3815B shall not exceed 67.0 MMBtu/hr on a higher heating value basis each. (ARM 17.8.749).

b. NO_X emissions from the common stack shall be controlled by a ULNB and shall not exceed:
   i. 0.051 lb/MMBtu 30-day rolling average (ARM 17.8.752).
   ii. 0.080 lb/MMBtu-HHV based on a 3-hour rolling average (ARM 17.8.749).

c. For process heaters (forced draft) with a rated capacity of greater than 40 MMBtu/hr-HHV, Calumet shall comply with 40 CFR 60, Subpart Ja. Each applicable process heater must meet the NO_X emission limits in either (b)(i) or (b)(ii), as follows (ARM 17.8.340 and 40 CFR 60, Subpart Ja):

   i. 60 ppmvd (corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

   ii. 0.060 lb/MMBtu-HHV basis determined daily on a 30-day rolling average basis.

d. Calumet shall control particulate matter (PM), PM with an aerodynamic diameter of 10 microns or less (PM_{10}), and PM with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$) emissions from each heater by utilizing good combustion practices and only combusting low sulfur fuels (ARM 17.8.752):

   i. PM/PM_{10} emissions shall not exceed 0.00051 lb/MMBtu.

ii. $PM_{2.5}$ emission shall not exceed 0.00042 lb/MMBtu.

e. Calumet shall control CO emissions using good combustion practices and CO emissions shall not exceed 0.03 lb/MMBtu or 17.6 tons per year based on a 12-month rolling average (ARM 17.8.752).

f. The combined carbon dioxide equivalent (CO_2e) emissions from the reformer heaters shall not exceed 133,038 TPY based on a 12-month rolling average (ARM 17.8.752).

g. Opacity shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

11. #2 Crude Unit process heaters (Atmospheric Heater H-2101, Vacuum Heater H-2102) and MHC process heaters (MHC Combined Feed Heater H-4101, MHC Fractionation Heater H-4102). Once DEQ receives written notification that H-4101 and H-4102 have been transferred to MRI, these two sources will no longer be regulated by this condition.

a. The maximum rated capacity of each unit shall not exceed the following on a higher heating value basis (ARM 17.8.749):

i. #2 Crude Atmospheric Heater H-2101: 71.0 MMBtu/hr.

ii. #2 Crude Vacuum Heater H-2102: 27.0 MMBtu/hr.

iii. MHC Combined Feed Heater H-4101: 54.0 MMBtu/hr.

iv. MHC Reactor Fractionation Heater H-4102: 38.0 MMBtu/hr.

b. Each fuel combustion device must be equipped with an ULNB and NO_X emissions shall not exceed the following on a higher heating value basis:

i. H-2101: 0.035 lb/MMBtu, 30-day rolling average basis as may be monitored via CEMS.

ii. H-2101: 0.042 lb/MMBtu, 3-hour rolling average basis as may be monitored via CEMS (ARM 17.8.749).

iii. H-2102: 0.040 lb/MMBtu, 3-hr average basis, as may be monitored via source testing.

iv. H-4101: 0.035 lb/MMBtu, 30-day rolling average basis as may be monitored via CEMS.

v. H-4101: 0.046 lb/MMBtu, 3-hour rolling average basis as may be monitored via CEMS (ARM 17.8.749).

vi. H-4102: 0.040 lb/MMBtu, 3-hr average basis, as may be monitored via source testing.

c. For process heaters (natural draft) with a rated capacity of greater than 40 MMBtu/hr-HHV, Calumet shall comply with 40 CFR 60 Subpart Ja. Each applicable process heater must meet the NO_X emission limits in either (b)(i) or (b)(ii), as follows (ARM 17.8.340 and 40 CFR 60, Subpart Ja):

   i. 40 ppmvd (corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

   ii. 0.040 lb/MMBtu-HHV basis determined daily on a 30-day rolling average basis.

d. Each applicable fuel gas combustion device shall comply with 40 CFR 60 Subpart Ja by meeting the applicable SO_2 or H_2S emission limit in 40 CFR 60 Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja):

   i. Calumet shall not discharge or cause the discharge of any gases into the atmosphere that contain SO_2 in excess of 20 ppmv (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling basis; and SO_2 in excess of 8 ppmv (dry basis corrected to 0-percent excess air) determined daily on a 365-successive calendar day rolling average basis; or

   ii. Calumet shall not burn in any fuel gas combustion device any fuel that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis, and H_2S in excess of 60 ppmv determined daily on a 365-successive calendar day rolling average basis.

e. Calumet shall control PM/PM_{10} and $PM_{2.5}$ emissions from each heater by utilizing good combustion practices and only combusting low sulfur fuels (ARM 17.8.752):

   i. PM/PM_{10} emissions from each heater shall not exceed 0.00051 lb/MMBtu, and

   ii. $PM_{2.5}$ emission from each heater shall not exceed 0.00042 lb/MMBtu.

f. Calumet shall control CO emissions from each process heater using good combustion practices. CO emissions from each heater shall not exceed 0.055 lb/MMBtu (ARM 17.8.752).

g. Calumet shall control CO_2e emission from each process heater by using low carbon fuels, good combustion practices and an energy efficient design. The CO_2e emissions shall not exceed (ARM 17.8.752):

   i. 142 lb/MMBtu for the Crude Heater (H-2101) and Vacuum Heater (H-2102).

   ii. 141 lb/MMBtu for the Combined Feed Heater (H-4101) and Fractionator Feed Heater (H-4102).

h. Opacity shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

12. Flare System (Flare #1 and Flare #2)

a. Calumet shall comply with the requirements of 40 CFR 60 Subpart Ja (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60, Subpart Ja).

13. Gasoline Truck Loading Rack

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 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. Calumet 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 17.8.752); and

ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% carbon dioxide (CO_2) (ARM 17.8.752).

14. Gasoline Railcar Loading Rack

a. The total VOC emissions to the atmosphere from the VCU due to loading gasoline into railcars shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.342 and 40 CFR Part 63.422, and ARM 17.8.752).

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

d. Calumet 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 17.8.752); and

ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO_2 (ARM 17.8.752).

15. FCCU

Calumet shall not cause or authorize to be discharged into the atmosphere from the FCCU emissions in excess of:

a. 15.0 lb/hr of PM (ARM 17.8.749).

b. Opacity shall not exceed 40%, except for one 6-minute average in any 1 hour (ARM 17.8.304).

c. CO

i. 500 ppmvd, at stack oxygen (or, "uncorrected") (40 CFR 63, Subpart UUU and 40 CFR 60, Subpart J),

ii. 500 ppmvd, 1-hour average at 0% O_2 (ARM 17.8.749),

iii. 100 ppmvd, on a 365-day rolling average at 0% O_2 (ARM 17.8.749).

d. SO_2

i. 50 ppmvd, on a 7-day rolling average at 0% O_2. SO_2 emissions during periods of startup, shutdown, or malfunction of the FCCU shall not be used in determining compliance with the 7-day rolling average SO_2 emissions limit provided that during such periods Calumet implements good air pollution control practices to minimize SO_2 emissions (ARM 17.8.749).

ii. 25 ppmvd, on a 365-day rolling average at 0% O_2 (ARM 17.8.749)

e. NO_X

i. 87 ppmvd, on a 7-day rolling average at 0% O_2. NOx emissions during periods of startup, shutdown, or malfunction of the FCCU shall not be used in determining compliance with the 7-day rolling average NOx emissions limit provided that during such periods Calumet implements good air pollution control practices to minimize NOx emissions (ARM 17.8.749).

ii. 68 ppmvd, on a 365-day rolling average at 0% O_2.

16. NO_X Umbrella Limit incorporated in MAQP #2161-30 and revised in MAQP #2161-38 (ARM 17.8.749):

In MAQP #2161-30, NO_X emissions were limited over multiple emitting units for purposes of avoiding PSD. Boiler #3, Crude Unit #2 Atmospheric Heater H-2101, Crude Unit #2 Vacuum Heater H-2102, Combined Feed Heater H-4101, MHC Reactor Fractionation Feed Heater H-4102, Hydrogen Plant #3 Reformer Heater H-3815A, and Hydrogen Plant #3 Reformer Heater H-3815B are considered new units for the underlying net emissions increase calculations. Boiler #1, Boiler #2, Crude Unit #1 Atmospheric Heater, and Crude Unit #1 Vacuum Heater are considered existing units.

NO_X emissions from the following units, combined, shall not exceed 103.02 tons per year as determined monthly on a rolling 12-month basis, for purposes of PSD avoidance for NO_X associated with the expansion project as permitted in MAQP #2161-30. The NO_X emission limit shall be reduced by the potential NO_X emissions from the RDU Combined Feed Heater (H-4101) of 3.83 TPY and from the Hydrogen Plant #3 Reform Heaters (H-3815A and H-3815B) of a combined 29.93 TPY, upon written notification to DEQ by Calumet that the sources have been transferred to MRI. This umbrella limit may be reduced in steps as sources are transferred. In MAQP #2161-38, H-4102 has been identified as continuing to operate at the MRL facility and therefore, the umbrella limit of 69.26 TPY has been further reduced by the NOx PTE of H-4102 (5.26 TPY). Calumet shall not exceed 64.0 TPY after the transfer of H-4101, H-3815A and H-3815B, while H-4102 continues to operate at MRL.

With exception of any unit equipped with NO_X CEMS verified via RATA, NO_X emissions shall be determined utilizing emissions factors determined via monthly portable analyzer results for 12 months, after which, emissions factors shall be determined based on source tests. Fuel flow shall be monitored continuously, and heat content of fuel gas determined no less than weekly. The monthly and rolling 12-month sums for the previous month shall be determined and recorded by no later than the 25th of each month. This limit is effective beginning with the first full month following the start of portable analyzer testing. Portable analyzer testing shall begin within 90 days after finalization of MAQP #2161-30 or upon startup of any affected unit, whichever is later.

- Boiler #1
- Boiler #2
- Crude Unit #1 Atmospheric Heater
- Crude Unit #1 Vacuum Heater
- Boiler #3
- Crude Unit #2 Atmospheric Heater H-2101
- Crude Unit #2 Vacuum Heater H-2102
- Combined Feed Heater H-4101, (until such time as DEQ receives notification it has been transferred to MRI)
- MHC Reactor Fractionation Feed Heater H-4102, (until such time as DEQ receives written notification it has been transferred to MRI)
- Hydrogen Plant #3 Reformer Heater H-3815A, (until such time as DEQ receives written notification it has been transferred to MRI)

- Hydrogen Plant #3 Reformer Heater H-3815B, (until such time as DEQ receives written notification it has been transferred to MRI.)

17. CO Umbrella Limit incorporated in MAQP #2161-30 and revised in MAQP #2161-38 (ARM 17.8.749):

In MAQP #2161-30, CO emissions were limited over multiple emitting units for purposes of avoiding PSD. Boiler #3, Crude Unit #2 Atmospheric Heater H-2101, Crude Vacuum Heater H-2102, Combined Feed Heater H-4101, MHC Reactor Fractionation Feed Heater H-4102, Hydrogen Plant #3 Reformer Heater H-3815A, and Hydrogen Plant #3 Reformer Heater H-3815B were new units. Boiler #1, Boiler #2, Crude Unit #1 Atmospheric Heater, and Crude Unit #1 Vacuum Heater are considered existing units for the underlying net emissions increase calculations.

CO emissions from the following units, combined, shall not exceed 55.08 tons per year as determined monthly on a rolling 12-month basis, for purposes of PSD avoidance for CO associated with the expansion project as permitted in MAQP #2161-30. The CO emission limit shall be reduced by the potential CO emissions from the RDU Combined Feed Heater (H-4101) of 6.02 TPY and from Hydrogen Plant #3 Reform Heaters (H-3815A and H-3815B) of a combined 17.61 TPY, upon written notification to DEQ by Calumet that the sources have been transferred to MRI. This umbrella limit may be reduced in steps as sources are transferred. In MAQP #2161-38, H-4102 has been identified as continuing to operate at the MRL facility and therefore, the umbrella limit of 31.45 TPY has been further reduced by the CO PTE of H-4102 (7.23 TPY). Calumet shall not exceed 24.22 TPY after the transfer of H-4101, H-3815A and H-3815B, while H-4102 continues to operate at MRL.

With exception of any unit equipped with CO CEMS verified via RATA, CO emissions shall be determined utilizing emissions factors determined via monthly portable analyzer results for 12 months, after which, emissions factors shall be determined based on annual source tests. Fuel flow shall be monitored continuously, and heat content of fuel gas determined no less than weekly. The monthly and rolling 12-month sums for the previous month shall be determined and recorded by no later than the 25th of each month. This limit is effective beginning with the first full month following the start of portable analyzer testing. Portable analyzer testing shall begin within 90 days after finalization of MAQP #2161-30 or upon startup of an affected unit, whichever is later.

- Boiler #1
- Boiler #2
- Crude Unit #1 Atmospheric Heater
- Crude Unit #1 Vacuum Heater
- Boiler #3
- Crude Unit #2 Atmospheric Heater H-2101
- Crude Unit #2 Vacuum Heater H-2102
- Combined Feed Heater H-4101, (until such time as DEQ receives written notification it has been transferred to MRI.)

- MHC Reactor Fractionation Feed Heater H-4102, (until such time as DEQ receives written notification it has been transferred to MRI.)
- Hydrogen Plant #3 Reformer Heater H-3815A, (until such time as DEQ receives written notification it has been transferred to MRI.)
- Hydrogen Plant #3 Reformer Heater H-3815B, (until such time as DEQ receives written notification it has been transferred to MRI.)

18. Catalytic Thermal Oxidizer (AOC-16 Remediation Project)

    a. The catalytic thermal oxidizer shall operate with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours, as determined by an initial performance test utilizing Method 22 to be conducted within 90 days of startup of the unit (ARM 17.8.752, ARM 17.8.749).

    b. Calumet shall operate all equipment to provide the maximum air pollution control for which it was designed (ARM 17.8.752(2)).

E. Testing and Monitoring Requirements

1. Refinery Fuel Gas Combustion Devices:

    a. Calumet shall install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases (except for SWS overhead gas) in accordance with the requirements of 40 CFR Part 60, Subparts A and J, for all fuel gas combustion devices, except those subject to 40 CFR 60 Subpart Ja, in which the monitoring requirements for 40 CFR 60 Subpart Ja applies (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60 Subpart J).

    b. Calumet shall install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases (except for SWS overhead gas) in accordance with the requirements of 40 CFR Part 60, Subparts A and Ja in order to demonstrate compliance with all refinery fuel gas combustion devices subject to 40 CFR 60 Subpart Ja (ARM 17.8.340 and 40 CFR 60 Subpart Ja).

    c. Calumet shall install, operate, calibrate and maintain on each applicable heater, an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_X emissions into the atmosphere pursuant to 40 CFR 60, Subpart Ja or complete biennial performance tests in accordance with 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60 Subpart Ja).

    d. By July 1, 2008, Calumet shall install and operate an SO_2 and O_2 CEMS and a volumetric flow rate monitor on the stack for the #1 and #2 Boilers, to be used as the primary analytical instrument to determine compliance with state and federal SO_2 requirements. By July 1, 2008, Calumet shall initially certify the #1 and #2 Boiler SO_2/O_2 CEMS and the volumetric flow rate monitor in accordance with 40 CFR Part 60, Performance Specifications 2 and 3 and 6.

After initial certification, Calumet shall conduct annual Relative Accuracy Test Audits (RATA) of the #1 and #2 Boiler SO_2/O_2 CEMS, and volumetric flow rate monitoring conformance with 40 CFR 60, Appendix F. After initial certification, Calumet shall also continue to implement all of the requirements of 40 CFR 60.13 and 40 CFR 60, Appendices B and F for the #1 and #2 Boilers SO_2/O_2 CEMS and flow rate monitor. (May 2008 Administrative Order on Consent and ARM 17.8.749).

2. Units Subject to the NO_X Umbrella Limitation of Section II.

   a. Each unit subject to the NO_X umbrella limitation and not equipped with validated (RATA conducted) CEMS meeting 40 CFR 60 Subpart A and Ja requirements, shall have annual Method 7E source tests (or testing as approved by DEQ), with the first source test to be conducted no later than 12 months after finalization of MAQP #2161-30. All testing shall be conducted concurrently with CO testing. Units equipped with NO_X CEMS shall conduct a RATA as required. Emissions factors in units of lb/MMBtu shall be determined from the most recent emissions testing (portable analyzer test, source test, or performance test (i.e. RATA testing, as applicable) (ARM 17.8.749).

   b. For any refinery fuel gas fired units subject to the NO_X umbrella limit in which a NO_X CEMS verified via a RATA is not in place, Calumet shall, at least once every calendar month, conduct concurrent NO_X and CO monitoring utilizing a portable analyzer and submit the results in a format as provided by Attachment 1 on a semiannual basis (within 45 days of the end of each semiannual period). Such monitoring must begin no later than 90 days after finalization of MAQP #2161-30 and shall be conducted for no less than 12 consecutive months following finalization of MAQP #2161-30. Any subsequent source test indicating noncompliance with any NO_X or CO limit shall reinstate this requirement, until no less than 4 quarters of compliance is again achieved. Emissions factors in units of lb/MMBtu shall be determined from the most recent emissions testing (portable analyzer test, source test or performance test, as applicable) (ARM 17.8.749).

   c. A source testing protocol meeting the minimum requirements of Attachment 1 shall be submitted to DEQ no later than 30 days after finalization of MAQP #2161-30, and such revisions as may be required submitted such that an approved source test protocol is in place within 60 days after finalization of MAQP #2161-30. Calumet shall conduct portable analyzer testing as required by DEQ (ARM 17.8.749).

   d. Portable analyzer testing shall not be required in any month in which source testing or performance testing is performed (ARM 17.8.749).

3. Units Subject to CO Umbrella Limitation of Section II.

   a. For all units subject to the CO Umbrella Limitation of Section II. in which a validated CO CEMS is not utilized, Calumet shall test for CO currently with testing for NO_X (ARM 17.8.749). For any units equipped with NO_X CEMS

but no CO CEMS, CO testing concurrent with NO_X RATA Testing is acceptable. Units equipped with CO CEMS shall conduct a RATA as required and determine lb/MMBtu emissions factors during the RATA testing (ARM 17.8.749).

b. For any refinery fuel gas fired units subject to the CO umbrella limit in which a CO CEMS verified via a RATA is not utilized, Calumet shall, at least once every calendar month, conduct concurrent NO_X and CO monitoring utilizing a portable analyzer and submit the results in a format as provided by Attachment 1 on a semiannual basis (within 45 days of the end of each semiannual period). Such monitoring must begin no later than 90 days after finalization of MAQP #2161-30 and shall be conducted for no less than 12 consecutive months following finalization of MAQP #2161-30. Any subsequent source test indicating noncompliance with any NO_X or CO limit shall reinstate this requirement, until no less than 4 quarters of compliance is again achieved (ARM 17.8.749).

c. A source testing protocol meeting the minimum requirements of Attachment 1 shall be submitted to DEQ no later than 30 days after finalization of MAQP #2161-30, and such revisions as may be required submitted such that an approved source test protocol is in place within 60 days after finalization of MAQP #2161-30. Calumet shall conduct portable analyzer testing as required by DEQ (ARM 17.8.749).

4. Crude Heater #2 H-2101, Mild Hydrocracker Heater H-4101, and Hydrogen Plant #3 Reformer Heaters H-3815A and H-3815B shall be equipped with NO_X CEMS in compliance with 40 CFR 60, Subpart A and Ja by no later than June 30, 2018 (ARM 17.8.749). Once DEQ receives written notification that H-4101, H-3815A, and H-3815B have been transferred to MRI, the sources will no longer be regulated by this condition.

5. SWS Overhead Gas
   a. Calumet shall comply with the SO_2 monitoring requirements contained in 40 CFR 60 Subpart J during all times when the SWS overhead gas is combusted in the boilers (Boiler #1 and/or Boiler #2). Calumet shall conduct SO_2 stack monitoring to demonstrate compliance with 20 ppm (dry basis, zero percent excess air) SO_2 limitation (ARM 17.8.749, and 40 CFR 60 Subpart J).

6. Calumet shall install and use the following continuous emission monitoring system (CEMS) on the FCCU:

   a. SO_2 and O_2 (ARM 17.8.749 and 40 CFR 60, Subpart J)

   b. NO_X and O_2 (ARM 17.8.749)

   c. CO and O_2 (ARM 17.8.749, ARM 17.8.342 and 40 CFR 63 Subpart UUU)

   d. Opacity (ARM 17.8.340 and 40 CFR 60 Subpart J, and ARM 17.8.342 and 40 CFR 63 Subpart UUU)

7. Calumet shall install, certify, calibrate, maintain and operate the above-mentioned

Boiler #1 and Boiler #2 stack and FCCU CEMS in accordance with the requirements of 40 CFR 60.11, 60.13, and 60 Appendix A, and the applicable performance specification test of 40 CFR 60 Appendices B and F and 40 CFR 60, Subpart J. These CEMS are a means for demonstrating compliance with the relevant emission limits (ARM 17.8.749 and 40 CFR 60, Subpart J).

8. For both the gasoline truck loading rack and the gasoline railcar loading rack, Calumet shall install, calibrate, certify, operate and maintain a thermocouple with an associated recorder as a continuous parameter monitoring system (CPMS). A CPMS shall be located in each VCU firebox or in the ductwork immediately downstream from the firebox in a position before any substantial heat exchange occurs in accordance with 40 CFR 63.427, in order to demonstrate compliance with 40 CFR 63, Subpart R. Calumet shall operate the VCUs in a manner not to go below the operating parameter values established using the procedures in 40 CFR 63.425 (ARM 17.8.342 and 40 CFR 63 Subpart CC).

9. Calumet shall operate and maintain instrumentation for continuously monitoring the volumetric flow and sulfur content to the flare system in accordance with the requirements of 40 CFR 60 Subpart Ja (ARM 17.8.340 and 40 CFR 60 Subpart Ja).

10. The FCCU shall be tested for CO and SO_2 and the results submitted to DEQ in order to demonstrate compliance with the emission limits contained in Section II.C.13.c and d. The testing shall occur annually or according to another testing/monitoring schedule as may be approved by DEQ (ARM 17.8.105 and ARM 17.8.106).

12. All fuel combustion devices in the #2 Crude Unit shall be initially tested for NO_X and subject to the applicable performance testing requirements of 40 CFR 60, Subpart Ja (ARM 17.8.340 and ARM 17.8.749).

13. The owner or operator of each applicable fuel combustion device and flare subject to 40 CFR 60, Subpart Ja shall demonstrate initial compliance with the applicable emission limit in §60.102a according to the requirements of §60.8.

14. Calumet shall comply with all test methods and procedures as specified by 40 CFR 63.425(a) through (c), and 63.425(e) through (h). This shall apply to, but not be limited to, the gasoline and distillate truck loading rack, the gasoline railcar loading rack, the vapor processing systems, and all gasoline equipment.

15. The gasoline truck loading rack VCU shall be tested for total organic compounds and compliance demonstrated with the emission limitation contained in Section II.C.11 on an every 5-year basis or according to another testing/monitoring schedule as may be approved by DEQ. Calumet shall perform the test methods and procedures as specified in 40 CFR 63.425 (ARM 17.8.105 and 17.8.342).

16. The gasoline railcar loading rack VCU shall be initially tested for total organic compounds and compliance demonstrated with the emission limitation contained in Section II.C.12.a within 180 days of initial startup. Additional testing shall occur on an every 5-year basis or according to another testing/monitoring

schedule as may be approved by DEQ. Calumet shall perform the test methods and procedures as specified in 40 CFR 63.425 (ARM 17.8.105 and 17.8.342).

17. The gasoline railcar loading VCU shall be initially tested for CO and NO_X, concurrently, and compliance demonstrated with the emission limitations contained in Section II.C.12.b and c within 180 days of initial startup (ARM 17.8.105).

18. Fuel flow rates, production information, and any other data DEQ believes is necessary shall be recorded during the performance of source tests (ARM 17.8.749).

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

20. Calumet shall conduct a Method 22 on the thermal catalytic oxidizer required by Section II.C.16 within 90 days of startup of the unit. No source test protocol need be submitted prior to the test, provided the observations are conducted and recorded as required by Method 22. A source test report shall be submitted to DEQ within 15 days of completion of the test. (ARM 17.8.749).

21. DEQ may require further testing (ARM 17.8.105).

F. Compliance Determination

1. Facility-wide Refinery:

a. Compliance with the plant-wide SO_2 emission limitations contained in Section II.C.1.a shall be determined based on data taken from the refinery fuel gas H_2S monitoring systems required by 40 CFR 60, Subpart J or Ja, in conjunction with metered refinery fuel gas usage, data from the FCCU SO_2 CEMS, and the #1 and #2 Boiler SO_2 CEMS, and stack testing data (ARM 17.8.749).

b. Compliance with the plant-wide CO emission limitations contained in Section II.C.1.b shall be determined based on data from the FCCU CO CEMS and emission factors developed from stack tests of the Boiler #1, Boiler #2, Boiler #3, FCCU, product loading VCUs, and any other stack tests conducted (ARM 17.8.749).

c. By the 25th day of each month, Calumet shall calculate and record the monthly and rolling 12-month sum of NO_X emissions from each unit subject to the NO_X umbrella limitations for the previous month. Calumet shall also calculate and record, by the 25th of each month, the total monthly and rolling 12-month sum of emissions for the units combined for the previous 12 months (ARM 17.8.749).

d. By the 25th day of each month, Calumet shall calculate and record the monthly and rolling 12-month sum of CO emissions from each unit subject to the CO umbrella limitations for the previous month. Calumet shall also calculate and record, by the 25th of each month, the total monthly and rolling 12-month

sum of emissions for the units combined for the previous 12 months (ARM 17.8.749).

2. Boilers #1 and #2

   a. Compliance with Boilers #1 and #2 SO_2 emission limitations contained in Section II.C.3.a shall be based on the data from the SO_2/O_2 CEMS (May 2008 Administrative Order on Consent and ARM 17.8.749).

   b. In the event that the SO_2/O_2 CEMS or stack volumetric flow monitor is not operational, Calumet must (ARM 17.8.749):

      i. notify DEQ of the problem within 24 hours (by phone) followed by written notification within 7 days;

      ii. continue to monitor using the H_2S CEMS at the fuel gas drum (pre-combustion);

      iii. route all SWS overhead gas to the flare system caustic scrubber;

      iv. repair and/or replace the SO_2/O_2 CEMS equipment and continue to monitor compliance as required in Section II.F; and

      v. notify DEQ within 24-hours when the SO_2/O_2 CEMS is back on-line.

   c. Compliance with the #1 and #2 Boiler CO emission limits contained in Section II.C.2 shall be determined through compliance source testing and by using the actual fuel burning rates and the emission factors developed from the most recent compliance source test (ARM 17.8.749).

3. Boiler #3

   a. Compliance with the Boiler #3 refinery fuel gas H_2S limitations shall be based on the data from the H_2S CEMS at the fuel gas drum (pre-combustion) operated in compliance with 40 CFR 60 Subpart Ja (ARM 17.8.749).

   b. Calumet shall monitor NO_X emissions from Boiler #3 in accordance with 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja, ARM 17.8.749).

   c. Compliance with the Boiler #3 CO emission limits in Section II.C.3 shall be demonstrated through compliance source testing and by using the actual fuel burning rates and the emission factors developed from the most recent compliance source test (ARM 17.8.749).

4. HTU Heater (H-1701)

   Compliance determinations for NO_X and CO emission limits for the HTU Heater (H-1701) shall be based upon source testing and actual fuel burning rates and emission factors developed from the most recent compliance source test.

5. Hydrogen Plant(s) - Reformer Heaters

   a. Compliance determinations for NO_X and CO emission limits for Hydrogen Plant #1 reformer heater shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test.

   b. Compliance with NO_X and SO_2 emission limits for Hydrogen Plant #3 Reformer Heaters (H-3815A and H-3815B) shall be conducted in accordance with monitoring and testing requirements of 40 CFR 60 Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja), (until such time as DEQ receives written notification they have been transferred to MRI).

   c. Calumet shall submit all reporting and recordkeeping in accordance with the Greenhouse Gas Reporting Rule to demonstrate compliance with the CO_2e emission limits (until such time as DEQ receives written notification that the Hydrogen Plant #3 Reformer Heaters (H-3815A and H-3815B) have been transferred to MRI) (ARM 17.8.749).

6. Gasoline Truck Loading Rack VCU

   Compliance determinations for VOC, NO_x and CO emission limits for the gasoline truck loading rack VCU shall be based upon the most recent compliance source test as well as compliance with the designated operating parameter value using the thermocouple and recorder.

7. Gasoline Railcar Loading Rack VCU

   Compliance determinations for VOC, NO_X and CO emission limits for the gasoline railcar loading rack VCU shall be based upon the most recent compliance source test as well as compliance with the designated operating parameter value using the thermocouple and recorder.

8. FCCU

   Compliance determinations for the PM emission limit under Section II.C.12.a will be based on the annual source test conducted under Section II.E. Compliance determinations for CO, SO_2 and NO_X emission limits under Section II.C.13 will be based on the data from CEMS as well as the annual source test conducted under Section II.E.

9. #2 Crude Unit and MHC process heaters (H-2101, H-2102, H-4101, H-4102) (until such time as DEQ receives written notification H-4101 and H-4102 have been transferred to MRI).

   Compliance monitoring with NSPS Ja NO_X and SO_2 emission limits for these heaters shall be conducted in accordance with monitoring and testing requirements of 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

10. Flare System (Primary Flare #1 and Secondary Flare #2)

Calumet shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in the fuel gases before being burned in any fuel combustion device or flare. The H_2S monitor shall be installed, operated, and maintained in accordance with Performance Specification 7 of Appendix B to Part 60 (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

11. Compliance with the opacity limitations shall be determined according to 40 CFR 60, Appendix A, and Method 9 Visual Determination of Opacity of Emissions from Stationary Sources.

12. Calumet shall determine, and submit to DEQ for concurrence, an empirically determined "k" factor to multiply conductivity (in micro-siemens per centimeter) of cooling tower water by to determine total dissolved solids of the cooling tower water. Such k factor shall be proposed within 3 months of finalization of MAQP #2161-31. Thereafter, Calumet shall test a representative grab sample of cooling water tower water for conductivity no less than once per calendar quarter utilizing Method 120.1 conductivity test procedures, as found for use under 40 CFR 136, or alternatively, at a more frequent interval and/or with different methods as may be proposed in writing by Calumet and approved in writing by DEQ. The results shall be recorded and compared to the conductivity that would represent the 1,500-ppm total dissolved solids limit in a log (ARM 17.8.749). Calumet shall maintain, on-site, documentation regarding the drift rate of drift eliminators maintained on each cooling tower (ARM 17.8.749).

G. Reporting and Recordkeeping Requirements

1. Plant-wide Refinery

Calumet shall provide semiannual emission reports to demonstrate compliance with Section II.C.1.a using data required in Section II.F.1.a. The report shall include the following (ARM 17.8.749):

a. Facility-wide SO_2 emission estimates for each month, including:

i. Refinery fuel gas: daily H_2S monitoring data and refinery fuel gas usage.

ii. SO_2 CEMS Data from FCCU, and Boiler #1 and #2, converted to daily mass emissions.

b. Compliance source test data used to update emission factors, conducted during the reporting period.

c. Monitoring downtime that occurred during the reporting period.

2. Boilers #1 and #2

Calumet shall provide semiannual emission reports to demonstrate compliance with Section II.C.2 using data required in Section II.F.2. The report shall include the following (ARM 17.8.749):

a. SO_2 emission estimates for #1 and #2 Boilers for each month, including:

   i. Hourly SO_2 CEMS data for the reporting period.

   ii. Fuel gas H_2S analyzer data for the reporting period.

b. NO_X emission estimates for each month. The NO_X emission rates shall be reported as an hourly average and a monthly total.

c. CO emission estimates for the #1 and #2 Boilers for each month. The CO emission rate shall be reported as an hourly average.

d. Compliance source test data used to update emission factors, conducted during the reporting period.

e. Calumet shall maintain records of daily fuel usage (in MMscf/yr) of the #1 and # 2 Boilers. The fuel usage shall be reported annually for each Boiler based on a 12-month total (ARM 17.8.749).

f. Monitoring downtime that occurred during the reporting period.

3. Boiler #3

Calumet shall provide semiannual emission reports to demonstrate compliance with Section II.C.3 using data required in Section II.F.3. The report shall include the following (ARM 17.8.749):

a. SO_2 emission estimates for the Boiler #3 for each month, including:

   i. Fuel gas H_2S analyzer data for the reporting the data.

b. NO_X emission estimates for each month. The NO_X emission rates shall be reported as an hourly average.

c. CO emission estimates for the Boiler #3 for each month. The CO emission rate shall be reported as an hourly average.

d. Compliance source test data used to update emission factors conducted during the reporting period.

e. Monitoring downtime that occurred during the reporting period.

4. Gasoline Truck Loading Rack VCU

Calumet shall comply with all recordkeeping and reporting requirements, as applicable, of 40 CFR 63.654 and the referenced provisions in 40 CFR 63, Subpart R (ARM 17.8.342 and 40 CFR 63, Subpart CC).

5. Gasoline Railcar Loading Rack VCU

   Calumet shall comply with all recordkeeping and reporting requirements, as applicable, of 40 CFR 63.654 and the referenced provisions in 40 CFR 63, Subpart R (ARM 17.8.342 and 40 CFR 63, Subpart CC).

6. FCCU

   Calumet shall provide semiannual emission reports to demonstrate compliance with Section II.C.13 using data required in Section II.F.8. The report shall include the following (ARM 17.8.749):

   a. Emission estimates for NO_X, SO_2 and CO, for each month.

   b. Daily SO_2 CEMS data for the reporting period.

   c. Hourly NO_X and CO CEMS data for the reporting period.

   d. Operating times for the FCCU during the reporting period.

   e. Monitoring downtime that occurred during the reporting period.

7. All Emission Reports shall be submitted within 45 days following the end of the semiannual period (ARM 17.8.749).

8. Calumet shall maintain a file of all measurements from all CEMS and H_2S monitors, including, but not limited to: compliance data; performance testing measurements; all flow rate meter performance evaluations; all flow rate meter calibrations, checks, and audits. Adjustments and maintenance performed on these systems or devices shall be recorded in a permanent form suitable for inspection. The file shall be retained on site for at least 5 years following the date of such measurements and reports. Calumet shall supply these records to DEQ upon request (ARM 17.8.749).

9. Calumet shall report monthly and rolling 12-month sums for each unit under the NO_X and CO Umbrella limitations of Sections II.C.16 and II.C.17, on a semiannual basis. The report shall include monthly and rolling 12-month sums for each unit, and as a sum of all units (ARM 17.8.749).

H. Operational Reporting Requirements

1. Calumet 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 Emission Inventory contained in the Permit Analysis and sources identified in Section I of 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 may be used for

calculating operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. Calumet shall notify DEQ of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include a change of 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 information requested in ARM 17.8.745(l)(d) (ARM 17.8.745).

3. All records compiled in accordance with this permit must be maintained by Calumet as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by DEQ, and must be submitted to DEQ upon request (ARM 17.8.749).

I. Notification Requirements

1. Calumet shall provide DEQ with written notification of the following dates within the specified time periods (ARM 17.8.749):

   a. 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).

   b. 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).

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

2. Tank Construction

   Calumet shall provide notification of the actual start-up of tanks/process vessels #55, #130, #132 and #133 within 15 days after the actual start-up of each vessel.

3. Equipment Transfer to MRI

   Calumet shall provide DEQ with written notification of the actual transfer date of the following emission sources to MRI within 15 working days of the actual transfer date (ARM 17.8.749).

   a. MHC Combined Feed Heater (H-4101)
   b. MHC Fractionator Feed Heater (H-4102)
   c. Hydrogen Plant #3 Reformer Heater (H-3815A)

d. Hydrogen Plant #3 Reformer Heater (H-3815B)
e. Tanks #29, #50, #102, #112, #116, #128, and #140

4. Refinery Reconfiguration Project

Calumet shall provide DEQ with written notification within 15 working days of the date the HTU increases its capacity for the Refinery Reconfiguration Project.

SECTION III: General Conditions

A. Inspection – Calumet 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 (Continuous Emissions Monitoring System (CEMS) and Continuous Emissions Rate Monitoring System (CERMS)) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

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

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving Calumet 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 action 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. Permit Fee – Pursuant to Section 75-2-220, MCA, failure to pay the annual operation fee by Calumet may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

H. 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).

Summary of Attachments

Attachment 1	PORTABLE ELECTROCHEMICAL (EC) ANALYZER TESTING FOR NO_X AND CO UMBRELLA LIMIT MONITORING

ATTACHMENT 1

Portable Electrochemical (EC) Analyzer Testing for NO_X and CO Umbrella Limit Monitoring

Calumet shall submit a source testing protocol, intended to be applicable for 5 years from the acceptance date, regarding details of the portable testing plan. The following are guidelines which outline the minimum requirements to be met in such submittal.

Analyzer Apparatus

1. Use any measurement system that meets the performance and design specifications of this guidance. The sampling system should maintain the gas sample at conditions that will prevent condensation in the lines or when it contacts the EC cells. Some of the components of an appropriate measurement system are described below.

2. The sample probe and sample line should be made of glass, stainless steel or other non-reactive material and should be designed to prevent condensation.

3. The calibration assembly should introduce calibration gases at ambient pressure to the sample probe during calibration checks. The assembly should be designed such that only the calibration gases are processed and that the calibration gases flow through all the filters in the sampling line.

4. The moisture removal system should be used to remove condensate from the sample gas while maintaining minimal contact between the condensate and the sample gases.

5. Particulate filters should be utilized before the inlet of the EC analyzer to prevent accumulation of particulate material in the measurement system and to extend the useful life of the EC analyzer. All filters should be fabricated of materials that are non-reactive to the gases being sampled.

6. The sample pump should be a leak-free pump that will transport the sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If upstream of the EC cells, the pump should be constructed of material that is non-reactive to the gases being sampled.

7. The sample flow rate should not vary by more than 10% throughout the calibration, testing, and drift check.

8. Interference gas scrubbers should be checked and replenished in accordance with the manufacturer's recommendations. EC analyzers should have a means to determine when the agent is depleted.

9. A data recorder should be used for recording the EC analyzer data.

EC Analyzer Calibration and Testing Specifications:

1. For purposes of testing for submission to DEQ, all combustion equipment shall be tested "as-found." No tuning or maintenance for the purpose of lowering tested emissions is allowed within 24 hours prior to testing.

2. Each EC analyzer should be certified by the manufacturer at least once per year unless waived by DEQ. Assemble the measurement system by following the manufacturer's recommended procedures for preparing and preconditioning the EC analyzer. Ensure the system has no leaks and verify that the gas-scrubbing agent is not depleted. When an EC cell is replaced, the EC analyzer should be re-calibrated.

3. Calibration of the EC analyzer should be done using certified calibration gases (EPA Protocol gases). Fresh air, free from ambient CO and NO_X, is permitted for O_2 calibration (20.9% O_2), and as a zero gas for CO and NO_X. Calibration gases for NO, NO_2, and CO should be chosen so that the concentration of the calibration gas is between 20% and 125% of the range of concentrations of the EC analyzer cell for each pollutant. Alternatively, calibration gases should not exceed 200% of the anticipated concentration expected from the emission unit being tested. If the measured concentration exceeds 125% of the span of the EC analyzer, at any time during the sampling run, that test run should be considered invalid. For NO_2 concentrations below 10% of the total NO_X concentration, NO_2 does not have to be measured directly and calibration of the EC analyzer for NO_2 is not required.

4. Inject each calibration gas into the EC analyzer and record the start time, response time, and concentrations. Gases should be injected through the entire sample handling system. All EC analyzer output responses should be recorded at least once per minute. The response time is the time it takes for the EC analyzer to get a steady response from a calibration gas after injecting the calibration gas into the measurement system. Actual measurements should not be averaged until the after the response time of the measurement system. After each calibration gas run, the EC analyzer should be refreshed with fresh air, free from CO, NO_X, and other pollutants. Repeat these steps for each calibration gas.

5. For the EC analyzer O_2 cell calibration, the minimum detectable limit should be 0.3%. For the EC analyzer NO_X and CO cells, the minimum detectable limit should be 2% of the calibration gas or 2 ppm whichever is less restrictive. If an invalid calibration is exhibited, corrective action should be taken, and the EC analyzer calibration check should be repeated until an acceptable EC analyzer performance is achieved.

6. Calculate the mean of the readings from the EC analyzer for each calibration gas. The average calculated EC analyzer response error for each calibration gas should not exceed ±5% of the calibration gas concentration. The maximum allowable deviation of any single reading, after the response time and prior to the refresh period, should not exceed ±2% of the average calculated EC analyzer response. For example: For a calibration gas with a concentration of 100 ppm, the calibration gas check should be considered valid only if the average of the measured concentrations for that calibration gas are within 5 ppm of 100 ppm, i.e., 95 to 105 ppm, and if the maximum deviation of any single measurement comprising that average is less than 2% or approximately 2 ppm.

7. During calibration an interference check should be performed. During the calibration check of a single gas species (e.g., NO & NO_2), record the response displayed by the other EC cells (i.e., CO & NO). Record the interference response for each EC cell to each calibration gas. The CO, NO, and NO_2 interference response should not exceed 5% of the calibration gas concentration. EC analyzers that have been verified for interference response using an interference scrubber are considered to be in compliance with this interference check specification when the interference scrubber is replenished per manufacturer's specifications.

The potential for interference from other flue gas constituents should be reviewed with the EC analyzer manufacturer based on site-specific data.

8. A post-test calibration check should be performed in the same manner as the pre-test calibration after each emissions unit test. If the post-test calibration checks do not meet the required specifications, all test data for that emissions unit should be considered null and void and re-calibration and re-testing should be conducted. To prevent loss of data, the drift of the analyzer should be determined after each measurement cycle. This should be done by performing a calibration check after each measurement cycle and determining the drift to ensure that it is still within the limit of ±5%. No changes to the sampling system or EC analyzer calibration should be made until all post-test calibration checks have been recorded. The difference (% Drift) between the pre-test calibration and the post-test calibration should not exceed 5% for each pollutant.

EMISSIONS MEASUREMENTS

1. Testing should be conducted by personnel trained in the use of the specific EC analyzer utilized for the testing. Samples of pollutant concentrations should be taken from sample ports in the stack or using a "Shepard's hook" from a location in the stack such that a representative concentration is measured and bias (e.g., air leakage at weep holes) is prevented. A single sampling location near the center of the duct may be selected.

2. Prior to sample collection, ensure that the pre-test calibration has been performed. Zero the EC analyzer with fresh air, free from ambient CO and NO_X or other combustion gases. Each test for an emission unit should consist of at least three 10-minute measurement cycles. Position the probe at the sampling point and begin the measurement cycle at the same flow rate used during the calibration check. Measurements should not be recorded and averaged until the measurement system response time has passed. The EC analyzer should be "refreshed," the analyzer drift should be determined, and the moisture collection system emptied after each sampling cycle. Use the measurement data to calculate the mean effluent concentration. The Data recorder should record a reading at least every 60 seconds. Record the average gas sample concentration for each pollutant from the cycle on a form similar to the one provided.

3. Conduct the post-test calibration check after testing of each emission unit. If the sampling system is disassembled or if the EC analyzer calibration is adjusted, the EC analyzer should be recalibrated before conducting the next emission unit test.

4. The emissions testing should produce at least three sets of concentration data for each pollutant of concern. Results from each test represent a "quasi steady-state" measurement of pollutant concentration and the measured pollutant concentrations should be calculated as the mean gas concentration using the emissions data collected during the three test runs. Data from additional tests may be included in the calculation so long as other operational parameters remain relatively unchanged. To maintain consistency, the run length should be the same for all runs and all units.

5. The measured pollutant concentrations should then be corrected to give actual values using the pre-test calibration and post-test calibration results. The following equation should be used.

$$C_{ACTUAL} := (C_{MEAS} - C_{CZ}) \cdot \frac{(C_{CAL} - C_{CZ})}{(C_{CM} - C_{CZ})}$$

Where:

C_{ACTUAL} = actual pollutant concentration, ppmdv

C_{MEAS} = measured pollutant concentration, ppmdv

C_{CAL} = concentration of the calibration gas, ppmv

C_{CZ} = average of pre-test and post-test calibration zero checks, ppmdv

C_{CM} = average of pre-test and post-test measured concentrations of the calibration gas measurement checks, ppmdv

Operational Parameter Measurements:

1. During the emissions testing of the emission unit, the following operational parameters should be measured or determined:

   a. % Firing Rate
   b. Fuel Btu content
   c. Fuel Consumption

2. Sampling of the fuel, that is representative of the fuel combusted in the emission unit, should be performed. The fuel sampling should be conducted within a 24-hour period of the testing. The sample should be taken from the inlet gas line, downstream from any inlet separator, using a manifold to remove entrained liquids from the sample and probe to collect the sample from the center of the gas line.

3. The stack velocity or flow shall be measured or determined using one of the following methods:

   a. EPA Reference Method 19
   b. A method as approved by DEQ, such as Method 2

Calculations and Requirements for a Valid Test Run:

Oxygen Based F Factor, Dry Basis

Use Method 19 equation 19-1.

$E=C_dF_d*(20.9/(20.9-\%O_2dry))$

Fd Calculation:

Use Method 19 Equation 19-13.

$$F_d = \frac{K(K_{kd}\%H + K_c\%C + K_s\%S + K_n\%N - K_o\%O)}{GCV} \qquad \text{Eq. 19-13}$$

Calibration Error:

Calibration Error = (Analyzer Response – Calibration Gas Concentration) / (Calibration Gas Concentration) * 100%. This value must be < 5% for a valid run.

% Interference

% Interference = Analyzer Response/Calibration Gas Concentration * 100%. This value must be <5% for a valid run.

% Drift

% Drift = (Post Test Analyzer Response – Pre-Test Analyzer Response)/(Pre Test Analyzer Response) * 100%. This value must be less than 5% for a valid test run.

Training:

Any persons performing the portable analyzer testing should be trained in the use of that portable analyzer and the associated concepts and principles of the emissions measurements and associated calculations.

Reporting

1. Use the following form when reporting results. This form is available electronically in Excel format and is available upon request, and is required to be reported on a semiannual basis.

2. Testing results that show emissions factors which are 10% or more higher than established during the last source test for the emitting unit, shall be reported within 2 weeks of the test. Such results will trigger the need for a full source test.

Calumet Portable Analyzer Emission Check Monthly Monitoring Report					
Tester Name				Ambient Temperature (°F)	
Tester Signature				Barometric Pressure (" Hg)	
Tester Title and Affiliation:				Date	
Emitting Unit Name as indicated in MAQP					
Fuel Factor (Fd) (dscf/MMBtu, as determined via Method 19 ultimate analysis on fuel burned on the testing date)					
Time Start					
Time Stop					
Check Zero NOx					
Check Zero CO					
Check Zero O2					
Check Span NOx (ppm)					
Check Span CO (ppm)					
Check Span O2 (ppm)					
Measured NOx (ppm)					
Measured CO (ppm)					
% O2					
Flue Gas Temp. (°F)					
Moisture (%)					
Check Zero NOx					
Check Zero CO					
Check Zero O2					
Check Span NOx (ppm)					
Check Span CO (ppm)					
Check Span O2 (ppm)					
NOx Calibration Error (%)					
NOx Interference (%)					
NOx Drift (%)					
CO Calibration Error (%)					
CO Interference (%)					
CO Drift (%)					
average % firing rate					
Maximum Rated Design Capacity (MMBtu/hr)					
Estimated lb/MMBtu emissions rate:					

notes: See Appendix 2 of the MAQP for equations, testing requirements, QA/QC requirements, and etc.

Montana Air Quality Permit (MAQP) Analysis
Calumet Montana Refining, LLC
MAQP #2161-39

I. Introduction/Process Description

Calumet Montana Refining, LLC (Calumet) operates a petroleum refinery located at the NE ¼ of Section 1, Township 20 North, Range 3 East, in Cascade County, Montana. The refinery is located along the Missouri River in Great Falls, Montana.

A. Permitted Equipment

The major permitted equipment at Calumet includes the following emission source, and the listing below includes identification of the equipment planned for transfer to the Montana Renewables, Inc. (MRI) for operation of the Great Falls Renewable Diesel Plant's Renewable Diesel Unit (RDU) as well as the new equipment that is part of the Refinery Reconfiguration Project and the recent *de minimis* change known as the Canola Oil Project:

#1 Crude Unit, including

- Crude Heater H-0101 (30 million British thermal units per hour (MMBtu/hr))
- Vacuum Heater H-0102 (7 MMBtu/hr)

#2 Crude Unit, including

- Crude Heater H-2101 (71 MMBtu/hr)
- Vacuum Heater H-2102 (27 MMBtu/hr)
- Off-gas compressor (a primary compressor and a backup compressor) (NEW)

Catalytic Poly Unit

Fluidized Catalytic Cracking Unit (FCCU), including

- FCCU Preheater H-0302 (8.9 MMBtu/hr)
- FCCU Catalyst Regenerator

Mild Hydrocracker Unit (MHC), (Planned for transfer to MRI)

- Combined Feed Heater H-4101 (54 MMBtu/hr) (Planned for transfer to MRI)
- Fractionator Feed Heater H-4102 (38 MMBtu/hr) (Planned for transfer to MRI)

Catalytic Reformer and Naphtha Unit, including

- Reformer Heater H-0403 (24.2 MMBtu/hr, HHV)
- Naphtha HDS Heater H-0402a (13.6 MMBtu/hr, HHV)
- Naphtha Splitter Reboiler H-0405 (9.9 MMBtu/hr, HHV)
- Naphtha Hydrodesulfurization (HDS) Unit
- Kerosene HDS Unit

Alkylation Unit, including

- Deisobutanizer reboiler (28 MMBtu/hr)

Hydrogen Plants, including

- Hydrogen Plant #1 Reformer Heater H-1801 (23.8 MMBtu/hr)
- Hydrogen Plant #2 Reformer Heater H-2815 (80 MMBtu/hr)
- Hydrogen Plant #3 Reformer Heaters (H-3815A & H-3815B, each rated at 67 MMBtu/hr, going to combined stack) (Planned for transfer to MRI)

Hydrotreater Unit (HTU), including

- Kerosene Heater
- HTU Heater H-1701 (22.5 MMBtu/hr, HHV)

Sodium Hydrosulfide (NaHS) Unit

Polymer-Modified Asphalt (PMA) Unit, including

- D-1901 – wetting tank (New larger tank added in MAQP #2161-35)
- RT-1901 – reactor tank
- Tank 130: 1,007 bbl for PMA Preparation
- Tank 132: 1,007 bbl for PMA Preparation
- Tank 133: 1,007 bbl for PMA Preparation
- Tank D-1906: 55 bbl Hot Oil Expansion Tank
- Tank D-1907: 72 bbl Crosslinking Tank
- Prilled Sulfur Handling Operations

Product Loading, including

- Truck Loading with Vapor Combustion Unit (VCU)
- Railcar Loading with VCU
- Railcar Loading (diesel and asphalt)

Utilities

- Boilers #1 & #2 with maximum rated capacity of 25 MMBtu/hr each
- Boiler #3 with maximum capacity of 60.5 MMBtu/hr
- Tank D-1908: 55 bbl Hot Oil Expansion Tank
- Wastewater
  - Surge Tank T-143, 18,000 bbl external floating roof
  - Surge Tank T-145, 37,000 bbl external floating roof
  - Aeration Tank TK-146
  - Slop Oil Tank 144, 600 bbl
  - Slop Oil Tank 144B, 300 bbl
  - Slop Oil Tank 186, 600 bbl each
  - API Separator
  - DAF Unit (Existing and New DAF unit in series)
  - Drains

- North and South Cooling Towers

Storage Tanks, including:
Tank 1: 152 bbl, Fixed Roof in Jet Fuel Additive service
Tank 2: 800 bbl Pressure Vessel in Propane service
Tank 3: 2,000 bbl Pressure Vessel in Isobutane service
Tank 4: 600 bbl Pressure Vessel in Butane service
Tank 5: 600 bbl Pressure Vessel in Isobutane service
Tank 10: 375 bbl Fixed Roof tank in Transmix service
Tank 14: 1,400 bbl Pressure Vessel in Isobutane service
Tank 15: 1,400 bbl Pressure Vessel in Butane service
Tank 29: 20,600 bbl Fixed Roof in Distillate service (Planned for transfer to MRI)
Tank 47: 20,500 bbl Fixed Roof in Middle Distillates service
Tank 48: 20,500 bbl Fixed Roof in Middle Distillates service
Tank 49: 20,500 bbl Fixed Roof in Middle Distillates service
Tank 50: fixed roof tank in asphalt storage service (Planned for transfer to MRI)
Tank 51: 21,000 bbl Fixed Roof in Kerosene / Jet Fuel service
Tank 52: 19,000 bbl External Floating Roof in Gasoline service
Tank 55: 3,022 bbl in Asphalt Service

Tank 58: 20,983 bbl Fixed Roof in Middle Distillates service
Tank 100: 1,100 bbl Fixed Roof in #5 Fuel Oil or NaHS service
Tank 101: 1,100 bbl Fixed Roof in #5 Fuel Oil or NaHS service
Tank 102: Fixed Roof Tank in Asphalt service (Planned for transfer to MRI)
Tank 112: Fixed Roof Tank in Asphalt service (Planned for transfer to MRI)
Tank 116: 44,900 bbl Fixed Roof in Distillate service (Planned for transfer to MRI)
Tank 118: 2,000 bbl Fixed Roof in Asphalt Emulsion service
Tank 119: 2,000 bbl Fixed Roof in Asphalt Emulsion service
Tank 120: 2,200 bbl Fixed Roof in Asphalt Emulsion service
Tank 121: 2,200 bbl Fixed Roof in Asphalt Emulsion service
Tank 122: 21,900 bbl External Floating Roof in Gasoline service
Tank 123: 21,900 bbl External Floating Roof in Gasoline service
Tank 124: 21,500 bbl External Floating Roof in Naphtha service
Tank 125: 38,500 bbl Fixed Roof in Heavy Liquids Service
Tank 126: 29,500 bbl External Floating Roof in Gasoline service
Tank 127: 21,500 bbl External Floating Roof in Gasoline service
Tank 128: 21,500 bbl Fixed Roof in Heavy Liquids Service (Planned for transfer to MRI)
Tank 137: Fixed Roof in Asphalt Storage service
Tank 138: Fixed Roof in Asphalt Storage service
Tank 139: Fixed Roof in Asphalt Storage service
Tank 140: Fixed Roof in Asphalt Storage service (Planned for transfer to MRI)
Tank 150: 30,100 bbl Fixed Roof in Raw Kerosene service
Tank 170: 10,200 bbl Fixed Roof in Distillate service

Tank 171: 10,200 bbl Fixed Roof in Distillate service
Tank 175: 400 bbl Fixed Roof in Ethanol service
Tank 176: 5,000 bbl Internal Floating Roof in Ethanol service
Tank 201: 69,700 bbl External Floating Roof in Crude Oil service
Tank 202: 69,700 bbl External Floating Roof in Crude Oil service

Tanks Added Under the *de minimis* action known as the Canola Oil Project:

Three tanks of 21,000 gallons each for storage of approximately 29,000 gallons of Canola oil for storage on-site for up to 8 months.

Tanks Added Under the Refinery Reconfiguration Project:

Tank 58: 20,983 bbl Fixed Roof in Middle Distillates service

Stationary Internal Combustion Engines:

GEN1: 400 hp diesel fired Emergency Generator
AC1: 540 hp diesel fired Emergency Air Compressor Engine
WP1: 165 hp, diesel fired Emergency Storm Water Pump
WP2: 240 hp, diesel fired Tank 54 Emergency Fire Water Pump
WP3: 300 hp, diesel fired Tank 24 Emergency Fire Water Pump
WP4: 300 hp, diesel fired Tank 146 Emergency Fire Water Pump

Electric Catalytic Thermal Oxidizer for the AOC-16 Remediation Project

B. Source Description

Petroleum refining has been conducted at this site since the early 1920's. Calumet converts crude oil into a variety of petroleum products, including gasoline, diesel fuel, jet fuel, naphtha, asphalt, and NaHS.

C. Permit History

On December 2, 1985, the Montana Department of Health and Environmental Sciences and Montana Refining Company (MRC) signed a stipulation requiring MRC to obtain an air quality permit and stipulated that a permit emission limitation of 4,700 tons per year (TPY) carbon monoxide (CO) would constitute compliance with ambient CO standards. MRC submitted this permit application with the intentions of permitting its existing refining operations, including all equipment not already permitted.

On October 20, 1985, MRC was granted a general permit for their petroleum refinery and major refinery equipment located in Great Falls, Cascade County, Montana. The application was given **MAQP #2161**.

The first alteration to their original permit was given **MAQP #2161-A** and was issued on May 31, 1989. This alteration involved the addition of a deisobutanizer reboiler.

The second alteration was given **MAQP #2161-A1** and was issued on March 12, 1990. This project involved the installation of one 30,000-barrel gasoline storage tank and one 40,000-barrel crude oil storage tank at the present facility. Both tanks were installed with external

floating roof control.

The third alteration was given **MAQP #2161-A3** and was issued on December 18, 1990. This alteration consisted of the installation of a Hydrofluoric (HF) Acid Alkylation Unit, internal floating roofs at existing storage tanks, which had fixed roofs, and a safety flare.

The fourth alteration was given **MAQP #2161-04** and was issued on June 16, 1992. This alteration consisted of the installation of a NaHS unit at the existing Great Falls Refinery.

The NaHS unit receives refinery fuel gas (540,000 standard cubic foot per day (scf/day) maximum rated capacity) containing hydrogen sulfide (H_2S) and reacts with a sodium hydroxide caustic solution to remove virtually 100% of the H_2S by converting it to NaHS, a saleable product.

The resultant sweet fuel gas is burned, as before, in other process heaters. However, since the fuel gas contains virtually no H_2S, sulfur dioxide (SO_2) emissions from the process heaters, assuming no other changes, were decreased by nearly 60%. There was no decrease in permitted SO_2 emissions from this permit because the refinery wanted to retain the existing permitted SO_2 emission limitations, so it could charge less expensive, higher sulfur crude oil.

In the basic process, off-gases from product desulfurizing processes (fuel gases) are contacted with a caustic solution in a gas contractor. The resultant reaction solution is continually circulated until the caustic solution is essentially used up; NaHS product is then sent to storage. Make-up caustic is added to the process as required. The process requires a gas contractor, process heat exchanger, circulation pump, storage tanks for fresh caustic and NaHS product, 12 pipeline valves, 4 open-ended valves, 21 flanges, and other process control equipment.

The only process emissions are fugitive Volatile Organic Compounds (VOC) from equipment (valves and flanges) in fuel gas stream service. To estimate unit VOC emissions, emission factors developed by the Environmental Protection Agency (EPA) for equipment in gas vapor service with measured emissions from 0 to 1,000 parts per million (ppm) are used. With an aggressive monitoring and maintenance program, fugitive VOC emissions from valves and flanges are within this 0 to 1,000-ppm range. Total annual fugitive VOC emissions from the NaHS units are estimated to be 20 pounds per year.

The tank that is to be used to store NaHS product was in jet fuel service. When taken out of jet fuel service, this tank (#35) is no longer a source of VOC emissions; the reduction in VOC emissions will be 2,270 pounds per year (PPY). Considering the 2,270-PPY decrease due to tank #35 service change, the refinery realized a net decrease in annual VOC emissions of 2,250 PPY or 1.1 TPY.

The fifth alteration was given **MAQP #2161-05** and was issued on October 15, 1992. This permit alteration was for the construction and operation of two 20,000-barrel capacity aboveground storage tanks at its Great Falls Refinery. The new tanks contain heavy naphtha (#127) and raw diesel (#128).

Each tank was constructed of metal sections welded together that rest on a concrete ring wall foundation. External floating roofs with dual seals are installed on each tank for VOC

control.

On April 6, 1993, MRC was granted **MAQP # 2161-06** to construct and operate a HDS unit and hydrogen plant. This sixth alteration was required to go through New Source Review (NSR) - Prevention of Significant Deterioration (PSD) review for Oxides of Nitrogen (NO_X) and was deemed complete on February 22, 1993. The HDS project was designed to process 5,000 barrels per day (BPD) of diesel/gas oil and to reduce the sulfur content to 0.05 weight percent. The reduction of sulfur in diesel fuel and gasoline were mandated by the 1990 Clean Air Act Amendments and were accomplished by October 1993, and 1995, respectively. The desulfurizer unit operated by MRC was limited in size and throughput capacity to approximately 1,400 barrels per day.

The HDS project consisted of an HDS process unit and heater, hydrogen plant with reformer heater, and the removal of storage tanks #40 through #43. Tanks #40 and #41, which processed gas oil, were discontinued. Tanks #42 and #43 that process raw diesel were also discontinued. Tanks #44 and #111 were changed to gas oil use and Tank #45 which serviced JP-4 was changed to gas oil use.

On July 28, 1993, **MAQP #2161-07**, a modification to MRC's MAQP #2161-06, was issued to change the emission control requirements of the Section titled "Pressure Vessels."

In a system where the valves relieve to atmosphere, rupture discs can prevent emissions in the event of relief valve leakage. In HF systems, they can provide some protection from acid corrosion on the relief valve and acid salt formation. Except where HF acid is present, rupture discs do not provide any additional protection, nor do they prevent any release of air contaminates in a closed relief system.

In heavy liquid service, rupture discs can be safety hazards by partial failure or leaking and changing, over time, the differential pressure required providing vessel protection. Therefore, only pressure vessels in HF Acid service shall be equipped with rupture discs upstream of the relief valves and all except storage tanks shall be vented to the flare system.

Also, the allowable particulate emission limitation for MRC's FCCU was corrected to reflect the maximum allowable emissions based on the process weight rule (Administrative Rules of Montana (ARM) 17.8.310). The maximum allowable emissions were calculated to be 234.53 TPY using a catalyst circulation rate of 125 tons per hour (TPH).

MRC requested a permit modification, **MAQP #2161-08**, to remove the alkylation unit and tanks #127 and #128 from New Source Performance Standards (NSPS) status because they were erroneously classified as affected facilities under NSPS when originally permitted. This request for modification was submitted on August 11, 1993, and issued on January 6, 1994.

When MRC applied for the preconstruction permit to build the HF Alkylation Unit in 1990, it was presumed, since this unit was new to MRC, it automatically fell under NSPS as new construction. Subsequently, it has been determined that if a source is moved as a unit from a location where operation occurred (Garden City, Kansas) to another location, it must meet the definition of reconstruction or modification in order to trigger NSPS applicability.

The alkylation plant was originally constructed in Garden City, Kansas during 1959 - 1960 and moved, in its entirety, to Great Falls and installed. Since the unit was originally constructed before the NSPS-affected date of January 5, 1981, it does not meet the criteria

for construction date of a new source under 40 Code of Federal Regulations (CFR), Subpart GGG or Subpart QQQ.

The project did not meet the criteria under reconstruction because no capital equipment was replaced when the unit was relocated. The replacement work performed, as the unit was moved, amounted to pump seals, valve packing, bearings, small amounts of corroded piping, and some heat exchanger tubes and bundles, all of which are done routinely as maintenance. The VOC emitters, such as valve packing and pump seals, were upgraded to meet Best Available Control Technology (BACT).

Along the same line, tanks #127 and #128 were originally constructed at Cody, Wyoming in 1960 and relocated to Great Falls in 1993. The only change was the modification of the roof seals to double seals to meet BACT. This cost of modification was a total of $15,000 for both tanks as compared to more than $500,000 if two new tanks were to be built.

Also, on October 28, 1993, MRC submitted a permit application to alter the existing permit. This modification and alteration of the existing permits were assigned MAQP #2161-08. MRC proposed to construct and operate a 3,500 barrel-per-day asphalt polymerization unit. The unit enabled MRC to produce a polymerized asphalt product that would meet future federal specifications for road asphalt, as well as supply polymerized asphalt to customers that wished to use the product.

The proposed unit consisted of two circuits: the asphalt circuit and the hot oil circuit. In the asphalt circuit, polymerization occurs in a 1,000-barrel steel, vented mix tank. Product blending and storage occurs in 3 steel, vented 1,000-barrel tanks identified as A, B, and C. Existing Tanks #55 and #56 (3,000 barrels each) remained in asphalt service and are used for storage. In addition to the above equipment, the asphalt circuit also consisted of 4 pumps and approximately 47 standard valves. All the above equipment became part of the asphalt service and, except for Tanks #55 and #56, was new.

To maintain the asphalt at the optimum temperature in the storage and blending tanks, a hot circuit was utilized. Hot oil (heavy fuel oil) was heated in an existing permitted process heater (Tank #56 heater) and circulated through coils in the process tankage. No change in the method of operation of the heater was anticipated. A steel vented hot-oil storage/supply tank was utilized to maintain the required amount of hot oil in the unit. In addition to the process heater and storage/supply tank, the hot-oil circuit consisted of one pump and approximately 56 standard valves. The above equipment was used in hot-oil service and, except for the heater, was new.

An annual emission increase of 7.3 TPY of VOC was expected due to operation of the unit. It was anticipated that the unit would be operated only 6 months of the year. The VOC emissions resulted from the vented hot-oil tank and the valves and pump in hot-oil service.

MAQP #2161-09 was issued on September 6, 1994, and included a change in the method of heating three previously permitted polymer modified asphalt tanks. As previously permitted, these tanks were heated utilizing circulating hot oil. The tanks were heated individually using natural gas fired fire-tube heaters. The use of natural gas eliminated the hot-oil circuit, including the hot-oil storage tank, entirely.

Since the initial permit application for the modified asphalt unit, several small design changes occurred involving the addition of a new 800-gallon wetting tank for asphalt service. An

output line from existing Tank #69 (Tall Oil) was also added. This output line added approximately 12 new valves and one new pump, all in Tall Oil service, to the unit. All other valves and pumps were designated to be in asphalt service.

All VOC emissions from equipment and tanks in asphalt service were assumed to be negligible, since asphalt has negligible vapor pressure at the working temperatures seen in the unit.

MAQP #2161-10, for the installation of an additional boiler (Boiler #3) to provide steam for the facility, was never issued as a final permit. On May 28, 1997, the Department of Environmental Quality (DEQ) – Air Resources Management Bureau received a letter requesting the withdrawal of the permit application and the withdrawal was granted to MRC. A summary of this permitting action is included in the analysis for MAQP #2161-11.

MAQP #2161-11 was issued on January 23, 1998, for the installation of a vapor collection system and enclosed flare for the reduction of Hazardous Air Pollutants (HAP) resulting from the loading of gasoline. This was done in order to comply with the gasoline loading rack provisions of 40 CFR 63, Subpart CC - National Emission Standards (NES) for Petroleum Refineries. A VCU was added to the truck loading rack. The gasoline vapors are collected from the trucks during loading then routed to an enclosed flare where combustion occurs. The result of this project was an overall reduction in the amount of VOC and HAPs emitted, and a slight increase in CO and NO_x emissions.

Because MRC's bulk gasoline and distillate truck loading rack VCU was defined as an incinerator under Montana Code Annotated (MCA) 75-2-215, a determination that the emissions from the VCU would constitute a negligible risk to public health was required prior to the issuance of a permit to the facility. MRC and DEQ identified the following HAPs from the flare that was used in the health risk assessment. These constituents are typical components of MRC's gasoline.

1. Benzene
2. Toluene
3. Ethyl Benzene
4. Xylenes
5. Hexane
6. 2,2,4-Trimethlypentane
7. Cumene
8. Naphthalene
9. 1,3-Butadiene

The reference concentrations for Benzene, Toluene, Ethyl Benzene, and Hexane were obtained from EPA's IRIS database. The risk information for the remaining HAPs was contained in the January 1992 CAPCOA Risk Assessment Guidelines. The ISCT3 modeling performed by MRC for HAPs identified above demonstrated compliance with the negligible risk requirement.

MRC requested, via a letter dated August 13, 1997, changes to administratively and technically correct MAQP #2161-09. These changes were necessary as a result of the withdrawal of MAQP #2161-10. The changes included correctly stating opacity limits relating to asphalt storage tanks, removing references to procedural rules, changing monitoring requirements for the HTU Sour Water Stripper (SWS) and changing

performance specifications for the continuous H_2S monitoring system.

DEQ issued Draft Modification #2161-11 on November 6, 1997, to address the permit changes that were requested by MRC. DEQ received comments on November 13, 1997, from MRC and later met on November 17, 1997, to discuss the draft modification. Because MRC had applied for a permit alteration on October 21, 1997, for the loading rack VCU, the draft modification was addressed in the permit alteration request.

DEQ issued Preliminary Determination #2161-11 on November 26, 1997. DEQ received comments from MRC on December 4, 1997, December 10, 1997, December 15, 1997, and December 30, 1997. DEQ responded to these comments via faxes on December 8, 1997, December 11, 1997, and December 16, 1997. On December 23, 1997, DEQ was prepared to issue a Department Decision, but MRC requested, via telephone, that the decision not be issued until after the holidays. The decision was required to be issued by January 8, 1998, to meet the mandated time frames for issuing a Department Decision.

MAQP #2161-12 was not issued. MRC applied for a modification on February 18, 1998, and this action was given #2161-12. On February 27, 1998, DEQ notified MRC that the permitting actions requested would require an alteration and that a complete preconstruction permit application would be required.

MAQP #2161-13 placed enforceable emission limits on the facility, both plant-wide and the #1 and #2 boilers. The emission limits showed, through the use of EPA-approved models, to protect the National Ambient Air Quality Standards (NAAQS) for SO_2.

The continuous gas flowmeters installed on the vacuum heater and the crude heater were placed in the permit. Also, the #1 and #2 boiler limits were updated to allow MRC more flexibility in their operations. The limits were originally placed on the boilers to keep MRC below the PSD permitting threshold. The new limits-maintained MRC's status below the PSD permitting threshold.

The monitoring location was identified in Attachment 1 Ambient Air Monitoring Plan. The current location was determined to be inappropriate after reviewing the modeling analysis, and the new location was approximately 1.2 km from its present location. The monitoring location was chosen based on the modeling analysis that was submitted and is required to provide monitored confirmation of compliance with the Montana SO_2 Standards.

The method numbers for examination of water and wastewater were updated. The conditions in MAQP #2161-13 were incorporated into the Operating Permit and the compliance demonstration methodology for those conditions was evaluated at the time of the Operating Permit's issuance. MAQP #2161-13 replaced MAQP #2161-11.

On August 6, 2001, DEQ issued **MAQP #2161-14** for the installation and operation of five 1600-kilowatt (kW) diesel-powered, temporary generators. These generators were necessary because of the current high cost of electricity. The generators would only operate for the length of time necessary for MRC to acquire a permanent, more economical, supply of power. Further, the generators are limited to a maximum operating period of 2 years.

Because these generators would only be used when commercial power is cost prohibitive, the amount of emissions expected during actual operation is minor. In addition, because the permit limits the operation of these generators to a time period of less than 2-years, the

installation and operation qualifies as a "temporary source" under the PSD permitting program. Therefore, the proposed project does not require compliance with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, DEQ requires compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 will be ensured. Finally, MRC is responsible for complying with all applicable ambient air quality standards. MAQP #2161-14 replaced MAQP #2161-13.

On August 17, 2002, DEQ issued **MAQP #2161-15** to eliminate the summer boiler SO_2 emission limits (both the plant-wide and 24-hour average) and redefine the winter limits as year-round limits. The seasonal limits were originally placed in the permit to allow MRC more flexibility when operating the boilers. Both the winter and summer scenarios were supported by ambient air quality modeling performed prior to MAQP #2161-13 being issued. The winter limit being redefined as a year-round limit does not represent an increase in SO_2 emissions from the boilers or any other emitting point. In addition, DEQ removed requirements to determine and report NO_X emissions both from the crude heater (due to the old SWS) and refinery wide, as these sources are not subject to NO_X emissions limitations. The requirements appeared to have been inadvertently applied through an administrative error. MRC already provides refinery-wide NO_X emissions as part of its annual Emission Inventory submission to DEQ. MAQP #2161-15 replaced MAQP #2161-14.

On March 19, 2003, DEQ issued **MAQP #2161-16** to include certain limits and standards associated with the Consent Decree lodged on December 20, 2001. In addition, the permit was updated with new rule references under ARM 17.8, Subchapter 7. MAQP #2161-16 replaced MAQP #2161-15.

DEQ received a request to modify MAQP #2161-16 on July 10, 2003, to change the emission testing schedule for the gasoline truck loading vapor combustion unit to be consistent with MRC's current operating permit. MRC also requested DEQ clarify the 7,000-BPD limit of crude charge (referenced in MRC's Title V Operating Permit) is no longer valid. Should MRC's normal processing exceed 7,000-BPD, MRC would be required to comply with ARM 17.8.324, as applicable. In a letter received by DEQ on September 30, 2003, MRC also requested to add three new asphalt tanks with associated natural gas heaters. The emissions from the three tanks met the requirements of the de minimis rule and were added to the permit. The permit action updated the permit to reflect the changes. **MAQP #2161-17** replaced MAQP #2161-16.

On May 14, 2004, DEQ received a letter from MRC requesting changes to MAQP #2161-17. The proposed change includes adding the ability to burn sweet gas in heaters at the HF Alkylation Unit, and at Tanks 102, 135, 137, 138, and 139. The sweet gas will have a H_2S limit equivalent to the 40 CFR Part 60, Standards of Performance for NSPS, Subpart J limit of 0.10 grains per dry standard cubic foot (gr/dscf) H_2S. The continuous refinery fuel gas monitoring system for H_2S installed on the fuel gas system that supplies the heaters would be used to determine compliance with the limit. Since the emissions from switching the fuel to sweet gas were less than the de minimis threshold, DEQ added the fuel switch. The permit action updated the permit to reflect these changes. **MAQP #2161-18** replaced MAQP #2161-17.

On May 17, 2007, DEQ received an application from MRC for the installation of a railcar product loading rack controlled by a John Zink VCU. On June 19, 2007, MRC clarified that

gasoline and naphtha were the only products that will go through the new railcar loading rack, and that other liquid products already loaded into railcars (diesel, jet fuel, etc.) would not be affected.

The gasoline railcar loading rack is subject to 40 CFR 63, Subpart CC, which requires MRC to comply with specific bulk loading requirements in 40 CFR 63, Subpart R. Subpart R restricts the operation of the railcar loading system to less than 10 milligrams (mg) of VOC per liter of gasoline loaded and requires the operation of a continuous monitor downstream from the firebox. Furthermore, the gasoline and naphtha railcars are considered as 'gasoline cargo tanks' and are required to comply with the leak detection testing requirements. Lastly, 40 CFR 63, Subpart CC requires MRC to comply with 40 CFR 60, Subpart VV to minimize fugitive equipment leaks.

Other new applicable regulations were added, including 40 CFR 63, Subpart UUU, Subpart EEEE, and Subpart DDDDD. Consent Decree #CIV-01-1422LH requirements, entered March 5, 2002 (Consent Decree), were included, such as the new requirements to comply with 40 CFR 60, Subpart J limits for refinery fuel gas and SWS overhead gas. Other changes completed in this permit action were adding FCCU uncorrected CO emissions from 40 CFR 63, Subpart UUU, and SO_2 and NO_X emission limits resulting from the Consent Decree; and revising the permit to reflect the operation of a continuous H_2S fuel gas meter and requirement to comply with 40 CFR 60, Subpart J. **MAQP #2161-19** replaced MAQP #2161-18.

On October 15, 2007, DEQ received a letter from MRC requesting a correction to MAQP #2161-19, to remove the restrictions on the type of fuel used in specific asphalt tank heaters, which was added erroneously during the previous permitting action. In addition, the MAQP was updated to reflect the fact that requirements under 40 CFR 63, Subpart DDDDD are now "state-only" since the federal rule was vacated in Federal Court on July 30, 2007. **MAQP #2161-20** replaced MAQP #2161-19.

On June 9, 2008, DEQ received a letter from MRC requesting an amendment to MAQP #2161-20, to modify the restrictions on Storage Tank #8. This request was a follow-up to a de minimis request received by DEQ on April 21, 2008, where MRC proposed to change the operation of Storage Tank #8 from NaHS to naphtha. DEQ reviewed this de minimis request and determined that MAQP #2161-20 must first be amended as described in ARM 17.8.745(2) and ARM 17.8.764 before this change would be allowed. Although the potential emissions increase for this project is less than the de minimis threshold, the proposal would have violated a condition of MRC's current permit. Specifically, the MAQP states, "Storage tanks #8, #9, #50, #55, #56, #69 #102, #110, #112, #130, #132, #133, and #135 shall be used for asphalt, modified asphalt, or tall oil service (ARM 17.8.749)." This permit has been amended to allow the proposed change in operation of Storage Tank #8.

On July 2, 2008, DEQ received another letter from MRC requesting an administrative amendment to MAQP #2161-20 to include certain conditions specified in the Administrative Order on Consent (AOC) that MRC entered into with DEQ on May 13, 2008. The AOC requires MRC to install and operate a SO_2 and Oxygen (O_2) continuous emission monitor system (CEMS) on the stack for the #1 and #2 Boilers. This SO_2/O_2 CEMS is to be used as the primary analytical instrument to determine compliance with state and federal SO_2 requirements. The AOC requires MRC to request that these conditions be included in the MAQP as enforceable permit conditions.

In addition, MRC requested that the permit be amended to allow certain de minimis changes related to the Diesel/Gas Oil HDS heater and three PMA tank heaters. Specifically, MRC requested that refinery fuel gas, in addition to natural gas, be allowed to be burned in these heaters. The current permit requires that the Diesel/Gas Oil HDS heater and the three PMA tank heaters be fired only with natural gas. This requirement is based on BACT. For the Diesel/Gas Oil HDS heater, the BACT analysis requires that low sulfur fuel be used. Since the refinery fuel gas is also a low sulfur fuel meeting 40 CFR 60, Subpart J requirements of 160 ppm H_2S, DEQ determined that the proposed change does not violate any applicable rule and therefore, can be allowed through an administrative amendment as specified in ARM 17.8.745(2) and ARM 17.8.764. For the three PMA tank heaters, however, the BACT analysis specifically requires that these heaters be fired with natural gas for control of NO_x emissions. Therefore, DEQ determined that the proposed three PMA tank heaters de minimis changes are prohibited under ARM 17.8.745(1)(a)(i) since an applicable rule, specifically ARM 17.8.752 requiring that BACT be utilized, would be violated. Because BACT determinations cannot be changed under the amendment process, DEQ requested that MRC submit an application for a permit modification that would include a revised BACT analysis in order to make the proposed change for the three PMA tank heaters.

In addition, DEQ updated Attachment 1 to reflect the most current permit language and requirements for ambient monitoring. **MAQP #2161-21** replaced MAQP #2161-20.

On December 19, 2008, DEQ received a request from MRC to amend MAQP #2161-21. MRC requested to change the wording for material stored in specified storage tanks to language representative of the requirements of 40 CFR 60, Subpart Kb in order to provide operational flexibility. Instead of referring to specific products (e.g., naphtha, gasoline, diesel, tall oil, etc.), the products would instead be referred to as light oils, medium oils, and heavy oils.

Under MRC's proposed language, light oils would be defined as a volatile organic liquid with a maximum true vapor pressure greater than or equal to 27.6 kilopascal (kPa), but less than 76.6 kPa and would include, but not be limited to, gasoline and naphtha. Medium oils would be defined as volatile organic liquids with a vapor pressure less than 27.6 kPa and greater than or equal to 5.2 kPa and would include, but not be limited to, ethanol. Heavy oils would be defined as volatile organic liquid with a maximum true vapor pressure less than 5.2 kPa and would include, but not be limited to diesel, kerosene, jet fuel, slurry oil, and asphalt.

In addition to making the requested change, DEQ has clarified the permit language for the bulk loading rack VCU regarding the products that may be loaded in the event the VCU is inoperable and deleted all references to 40 CFR 63, Subpart DDDDD: NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters, as it was removed from the ARM in October 2008. DEQ has also updated Attachment 1, Ambient Monitoring to reflect the most current permit language and requirements for ambient monitoring. **MAQP #2161-22** replaced MAQP #2161-21.

On July 9, 2009, DEQ received a permit application from MRC to modify MAQP #2161-22. The application was deemed complete on July 24, 2009. MRC submitted a permit modification to allow the use of treated refinery fuel gas or natural gas in the tank heaters. Previously, the PMA tanks heaters were permitted to use natural gas only pursuant to a BACT analysis that was completed for MAQP #2161-09. This permit modification applied to three previously permitted asphalt tanks (Tanks #130, 132 and 133) and the associated

PMA tank heaters. **MAQP #2161-23** replaced MAQP #2161-22.

On January 15, 2008, DEQ received a request from MRC to install a second hydrogen plant that utilizes a process heater with a heat input of 80 million British thermal units per hour (MMBtu/hr). DEQ approved this de minimis request on February 8, 2008. Pursuant to the Consent Decree (CD) and the approval of the de minimis request, MRC was required to conduct an initial performance test on the process heater with the results reported based upon the average of three, one-hour testing periods. The CD also required MRC to submit an application to DEQ and to propose a NO_x permit limit for the heater. MRC submitted a permit application on December 29, 2009, and DEQ deemed this application incomplete on January 15, 2010. On July 12, 2010, MRC submitted additional information as requested by DEQ. On September 2, 2010, during the comment period, MRC submitted information to support the guaranteed ultra-low NO_x burner emission limit of 0.033 lb/MMBtu based on the Higher Heating Value (HHV) of the fuel. This limit was based on the process heater of the hydrogen plant operating at full capacity (80 MMBtu/hr) with fuel gas consisting of 40.5 % natural gas and 59.4% Pressure Swing Adsorption (PSA) vent gas. This permit modification applied to NO_x limits on the Hydrogen Plant #2 process heater. **MAQP #2161-24** replaced MAQP #2161-23.

On July 6, 2011, MRC submitted a permit application and subsequent modeling demonstration to add a new boiler (Boiler #3) capable of firing refinery fuel gas, SWS overhead gas, or natural gas at the petroleum refinery. The primary purpose of Boiler #3 is to supplement the two existing boilers (#1 and #2) that provide process steam to the refinery. The design burner heat input capacity for Boiler #3 varies, depending upon fuel characteristics, from 59.7 to 60.5 MMBtu/hr. DEQ deemed the application incomplete on August 4, 2011, and MRC provided additional information in response to DEQ's letter on September 26, 2011.

On October 25, 2011, DEQ requested additional information with respect to MRC's plantwide applicability limit (PAL) and the SWS overhead gas combustion properties. This information was received by DEQ on November 15, 2011. Additionally, because MRC experienced significant downtime with the SO_2/O_2 CEMS required on the #1 and #2 Boiler stack, MRC submitted a request to allow the use of the H_2S fuel gas analyzer located near the fuel gas drum as backup to the SO_2/O_2 CEMS. MRC also requested this for Boiler #3.

Therefore, in addition to adding the Boiler #3 to the refinery's operation, the permit action also added compliance, reporting and recordkeeping requirements for allowing the H_2S fuel analyzer to be used as a backup to the SO_2/O_2 CEMS. When the H_2S fuel analyzer is used, MRC would not be allowed to route the SWS overhead gas to the boilers. **MAQP #2161-25** replaced MAQP #2161-24.

On October 24, 2012, DEQ received a request for the transfer of ownership. According to the information submitted, the previous owner, Connacher Oil and Gas, sold its shares of MRC to Calumet Specialty Products Partners. With the transfer of ownership, Calumet Specialty Products Partners also requested a facility name change from MRC to Calumet Montana Refining, LLC. This was an administrative permit action to change the name. **MAQP #2161-26** replaced MAQP #2161-25.

On July 30, 2013, DEQ received an application for modification to MAQP #2161-26. The permit action removed older storage tanks that were located close to the process unit area and in order to accommodate potential future expansion. As such, Calumet requested to

remove nine (9) tanks and to add eight (8) new tanks as shown in the table below:

Current Tank ID	Current Service	Current Capacity (in barrels (bbl))	New Tank ID	Service	New Capacity (in bbl)
Tank #122	Unleaded Gasoline	11300	Tank #122	Unleaded Gasoline	20000
Tank #123	Unleaded Gasoline	11300	Tank #123	Unleaded Gasoline	20000
Tank #52	Premium Gasoline	3000	Tank #52	Premium Gasoline	11300
Tank #53	Premium Gasoline	3000	Removed from service		
Tank #46	Kero/Jet A	5140	Tank #49	Kero/Jet A	20000
Tank #47	Kero/Jet A	10500	Tank #47	Kero/Jet A	20000
Tank #48	Kero/Jet A	10500	Tank #48	Kero/Jet A	20000
Tank #50	Asphalt	55700	Tank #50	Asphalt	20000
Tank #102	Asphalt	10300	Tank #102	Asphalt	20000

All kerosene and asphalt tanks were equipped with fixed roofs, and all gasoline storage tanks are equipped with external floating roofs. In addition, tanks 50 and 102 are equipped with two burners (John Zink Burner), each rated at 2.3 MMBtu/hr to keep the asphalt from cooling down and/or hardening. **MAQP #2161-27** replaced MAQP #2161-26.

On October 3, 2013, DEQ received a permit application requesting a major modification under the New Source Review-Prevention of Significant Deterioration (NSR-PSD) program. This permit application was assigned MAQP #2161-28. The project was deemed significant for greenhouses (GHG) and volatile organic compounds (VOCs), and the permit application was deemed complete on February 10, 2014.

With this permit action, Calumet proposed to increase the low sulfur fuels capacity at the refinery from approximately 10,000 bpsd throughput up to 30,000 bpsd while increasing yields of distillates, kerosene, diesel, and asphalt products.

The expansion project included the construction of four new processing units: a new crude unit that will process heavy sour crudes, a MHC for gas-oil conversion to higher value distillates, a new hydrogen plant (#3) to support the MHC, and a fuel gas treatment unit to handle the increased fuel gas production from the MHC.

The main emitting units included with the expansion project are as follows: Hydrogen Plant #3 (equipped with two heaters with a total combined firing rating of up to 134 million British thermal units per hour (MMBtu/hr)); Combined Feed Heater (up to 54 MMBtu/hr); Fractionation Feed Heater (up to 38 MMBtu/hr), Crude Heater (up to 71 MMBtu/hr), Vacuum Heater (up to 27 MMBtu/hr), and a new flare interconnected to the existing flare that will be equipped with a flare gas scrubber. With the expansion, Calumet also proposed to add a new rail car loading (diesel and asphalt) and unloading (crude oil and gas oil) area, and several new storage tanks in addition to re-purposing some existing storage tanks to accommodate the expansion project.

Additionally, the existing HTU that block operated in both diesel and gas-oil service was to become the kerosene HTU, and the existing kerosene HTU was to become a Naphtha

HTU. Lastly, Calumet requested a federally enforceable operational limit on Boiler #1 and Boiler #2.

DEQ issued a preliminary determination (PD) as **MAQP #2161-28** on March 18, 2014, final department decision (DD) on April 25, 2014, and final permit on May 13, 2014. However, DEQ did not notify the public by advertisement in a newspaper of general circulation in the Great Falls area in accordance with ARM 17.8.826(2)(c) when it issued the PD for MAQP #2161-28. Therefore, DEQ reissued its PD under **MAQP #2161-29** along with a public notice in the Great Falls Tribune to satisfy the requirements of ARM 17.8.826(2)(c). All project analyses and conclusions from MAQP #2161-28 for this project remained the same. MAQP #2161-29 contained any comments received on the PD for MAQP #2161-28 and corrections made to address them.

On April 4, 2017, DEQ received an application from Calumet to modify the existing MAQP. Incompleteness responses and additional information were received, with final information completing the application on September 26, 2017. Due to various operational and design issues, compliance with certain limits associated with the expansion project permitted in MAQP #2161-29 were determined to be unachievable on a continuous and ongoing basis. These limitations were necessary to avoid the project being determined a major modification of a major stationary source and subject to the permitting requirements of ARM 17.8 Subchapter 8 for NO_X. As such, Calumet proposed an alternative operating scenario and alternative limitations to maintain the project below relevant significant emissions rates.

Calumet proposed to install a new temporary low NO_X boiler (Boiler #4) for additional/supplemental steam production and an ammonia combustor to remove and combust fuel bound nitrogen that otherwise would be present in refinery fuel gas. In addition, Calumet proposed an umbrella limit on emissions of NO_X and CO on a rolling 12-month basis. The umbrella limit would apply to combined emissions from multiple units such that any combination of emissions from these units, provided the overall emissions limitation is adhered to, maintains the project as not a major modification for NO_X or CO. Prior limitations related to PSD avoidance on Boilers #1 and #2 have been removed from the permit.

Calumet has determined a need to reduce fuel-bound nitrogen in fuel gas in order to meet NO_X limitations on various units. Further, Calumet has identified mechanical issues with Boiler #3 which has resulted in the potential for excess NO_X emissions. Bringing a temporary low NO_X boiler on-site will allow Calumet to produce steam for operations while ongoing efforts are undertaken to reduce plant wide NO_X emissions. The low NO_X boiler will provide for reduced emissions of NO_X per pound of steam produced compared to the NO_X performance capabilities of Boilers #1 and #2.

Boiler #3, the new low NO_X boiler, and the ammonia combustor were determined technically and economically related to the expansion project and were included in the expansion project as new units. The purpose of this permitting action is to establish limits which maintain the net emissions increases to less than the significant emissions rates for NO_X and CO, or less than the amount of other emissions previously reviewed for the expansion project. All pollutants were reviewed, and the project was re-permitted as if the project had not been previously permitted. A request in the future to modify or replace associated units would require a reassessment of the project emissions. The allowable operating capacity of the associated refining unit heaters was reduced in the current

operational scenario, and future projects to reduce emissions will be necessary to gain full use of the increased refining capacity capable of being accomplished with the associated equipment installed for avoidance of PSD.

During PSD review, Calumet identified that Tank #50 and #102 will not be equipped with tank heaters and the emissions were removed from considerations in contemporaneous emissions increases. **MAQP #2161-30** replaced MAQP #2161-29.

On July 12, 2019, DEQ received from Calumet an application to modify the MAQP. Calumet sought to relax the control requirements on Tanks #125 and #128, due to a finding that the tanks are out-of-round, making seals associated with floating roof design to be infeasible to maintain. These tanks are in heavy liquid service, and as such, DEQ approved request to maintain these tanks as fixed roof tanks with submerged fill. In doing so, the emissions increases associated with the expansion project is updated, and Best Available Control Technology (BACT) review is presented in demonstration that the requirements of BACT are maintained (see the permit analysis). Condition III.B.7.h was established to require the fixed roof tanks be maintained in heavy liquids service with submerged fill practices maintained. Prior requirements that these tanks be maintained with floating roof design was removed. **MAQP #2161-32** replaced MAQP #2161-31.

On December 31, 2019, DEQ received from Calumet a concurrent MAQP and Title V application to revise nitrogen oxides (NO_X) limitations on the #2 Crude Vacuum Heater H-2102 and the Mild Hydrocracker Reactor Fractionation Heater H-4102. These heaters were assigned NO_X limitations as part of Best Available Control Technology (BACT) review associated with the refinery expansion project. The limits were originally set at 0.035 pounds per million British thermal units, on a higher heating value basis, on a 30-day rolling average.

The permit application requested that these limits be revised to 0.040 lb/MMBtu, on a 3-hr basis via an annual source test. The permit action provided for an achievable limitation which is practically enforceable without a requirement for CEMS. The mass-based umbrella limitations for NO_X and CO remained unchanged. **MAQP #2161-33** replaced MAQP #2161-32.

On February 19, 2021, DEQ received from Calumet an application to modify the MAQP for installation of a catalytic thermal oxidizer. Calumet implemented the AOC-16 Remediation Project at the Gasoline and Light Oil Loading Rack area, which included dual-phase extraction in an existing primary recovery trench in the truck rack area, and a passive treatment trench just north of North River Road. The installation of a vapor-liquid separator, with a catalytic thermal oxidizer to destroy VOC vapors, was included as part of this project.

In accord with ARM 17.8.770, a human health risk assessment on the air emissions from the catalytic thermal oxidizer was conducted. Further, a best available control technology review as required by ARM 17.8.752 was conducted. The analyses demonstrated the proposed oxidizer emissions would present a negligible risk to public health, safety, and welfare as defined in ARM 17.8.770, and meet the requirements of BACT as required by ARM 17.8.752. **MAQP #2161-34** replaced MAQP #2161-33.

On July 2, 2021, DEQ received from Calumet an application to modify the MAQP for installation of new equipment and tanks related to the polymer modified asphalt (PMA)

production process. This project was titled the Asphalt Upgrades Project. The Asphalt Upgrades Project provided the refinery with improved PMA production capabilities, more advanced asphalt product blending capabilities, and modernized heating systems for PMA process equipment, PMA storage tanks, and asphalt storage tanks. The project also included the shutdown of numerous heaters which were replaced with heaters fired by refinery fuel gas. The project also made changes to the asphalt product blending and storage operations at the refinery. **MAQP #2161-35** replaced MAQP #2161-34.

On August 6, 2021, DEQ received from Calumet an application to modify the MAQP as part of the Refinery Reconfiguration Project which entailed transferring some equipment from Calumet to Montana Renewables, Inc (MRI) for the Great Falls Renewable Diesel Unit (RDU). Additional information was submitted on September 16, 2021, in response to DEQ's incompleteness letter. The application also requested several changes to the existing equipment and to permit some new equipment. It's important to note that equipment scheduled to be transferred to MRI will remain as active equipment under the conditions of MAQP #2161-36 until such time as DEQ issues MRI a final MAQP for the operation of the equipment listed below at RDU and DEQ receives written notification from Calumet identifying the date that service of each piece of equipment listed below was transferred to MRI.

Following is a list of the equipment to be transferred to MRI:

- Mild Hydrocracker (MHC) Combined Feeder Heater (H-4101);
- MHC Fractionator Feed Heater (H-4102) (the emission source will be transferred to MRI, but H-4102 will be out of service because it will not be required to operate in the RDU);
- Hydrogen Plant #3 Reformer Heaters (H-3815A & H-3815B);
- Tanks #29, #50, #102, #112, #116, #125, #128, and #140; and
- MHC Hydrogen Plant #3, and Storage Tank Piping Fugitive Components and Wastewater Components.

The CO and NOx umbrella limits are to be reduced upon Calumet providing written notification that the following emission sources have been transferred to MRI: MHC Combined Feeder Heater (H-4101); MHC Fractionator Feed Heater (H-4102); and Hydrogen Plant #3 Reformer Heaters (H-3815A & H-3815B).

Calumet requested the following changes to existing emission sources that are to remain at the refinery but will be modified to adapt to changing operations as part of the Refinery Reconfiguration Project:

- Crude Unit #2 changes include:
  - changes to piping and valves,
  - modification of fractionator tower components,
  - add a primary off-gas compressor, and
  - add a backup off-gas compressor.
- Hydrotreating Unit (HTU) will be reconfigured to increase its capacity to provide flexibility in the petroleum derived feed streams it is capable of processing including the following changes:
- Purified hydrogen (an unregulated air compound) will be vented by a new stack at the MRI's RDU when there are abrupt process changes at hydrogen consuming process units or Hydrogen Plant #2.

- Allow Flare #1 to receive natural gas purges from MRI's new Hydrogen Plant #4.
- Add Tank #58 (which is reusing a tank designation), a fixed roof atmospheric storage tank that shall store middle distillates that the HTU will be capable of processing; and
- Change locations of some existing loading facilities to accommodate efficient loading and unloading of refinery and MRI's RDU materials separate from one another.

On August 2, 2021, Calumet submitted a *de minimis* change notification for the receipt of a single railcar of canola oil for receipt, unloading and storage. The canola will either be processed in the existing crude unit, transferred, and used by the MRI's RDU, or shipped offsite via railcar. No permit changes were deemed necessary for this *de minimis* change.

A description of the project impacted emitting units is in the table below:

Emissions Unit	Existing/ New Unit	Project Impact
HTU Heater (H-1701) (EPN 26)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. CMR estimated that the project may use all the heater's existing firing rate capacity that is not currently being used. CMR is not proposing to increase the firing rate capacity of the heater.
HTU Fractionation Heater (H-1730)	New	A new fractionation heater will be installed to support the HTU.
Flare #1 (FLR-0701) (EPN 32)	Existing	The flare will receive natural gas purges from the MRI Great Falls Renewable Diesel Plant's new Hydrogen Plant #4. Additionally, CMR anticipates a minor increase in the amount of excess RFG that will be routed to the flare due to a reduction in overall unit operating rates and process heater firing rates at the refinery.
Tank #58	New	A new storage tank will be installed at the refinery to store middle distillates.
Piping Fugitive Components (EPN 33)	Existing/ New	CMR plans to add piping fugitive components (e.g., pumps, compressors, pressure relief devices, open-ended valves or lines, valves, and flanges or other connectors) at the refinery as part of the project.
Wastewater Components	Existing/ New	CMR plans to add drains and sumps at the refinery as part of the project.
Railcar Unloading - Renewable Feed	New	CMR plans to install new railcar racks to unload renewable feed that will be routed to and used by the MRI Great Falls Renewable Diesel Plant.
Loading (EPNs 30 and 39)	Existing/ New	New loading facilities will be installed at the refinery and changes will be made to the location and use of certain existing loading facilities at the refinery to facilitate the efficient loading and unloading of refinery and MRI Great Falls Renewable Diesel Plant materials.
Loading VCU (EPNs 30 and 39)	Existing	In addition to controlling the loading of petroleum derived materials (gasoline and naphtha), the existing railcar VCU will be utilized to control the loading of renewable naphtha.

MAQP #2161-36 replaced MAQP #2161-35.

On December 7, 2021, DEQ received from Calumet a concurrent MAQP and Title V application. The application was considered complete on February 18, 2022. The permit action accomplished several updates, corrections, and changes as presented below:

1. Removal of preconstruction approval for the sour water stripper ammonia combustor. This portion of the permit had expired because it was over 3 years since the unit was permitted and construction had not commenced. Calumet was not seeking to renew approval as originally permitted. Conditions related to the ammonia combustor were removed from the permit.

2. Increase in allowable emissions from the Kerosene Hydrotreater Unit Heater H-1701. Calumet identified that the unit is capable of firing at a higher capacity than previously indicated. The unit was installed in 1992, and was not undergoing physical modification or operational change, however, Calumet requested that the allowable emissions on a pound per hour and ton per year basis be increased to match the realizable maximum capacity of the unit. The permit action defined the maximum allowable emissions (potential to emit) of this unit under the increased maximum firing rates identified. Oxides of Nitrogen limitations on a lb/MMBtu basis remain unchanged. Calumet accepted the responsibility for the guarantee of NO_X emissions when firing above a manufacturer's design firing rate.

3. Correct the listed maximum rated firing rate for the Hydrogen Plant #2 Reformer Heater H-2815. This heater was originally approved through de minimis and was presented as having an 80 MMBtu/hr maximum firing rate capacity. However, as part of the June 29, 2018, Title V permit renewal application, Calumet incorrectly identified the heater as a 65.2 MMBtu/hr heater. The capacity of the heater was listed in the Title V and MAQP as a 65.2 MMBtu/hr heater. The permit action corrected the indicated maximum capacity of the heater to 80 MMBtu/hr, as originally submitted. No change to permit limits or applicable regulatory requirements was necessary.

4. Increase the recognized maximum capacity of the Naphtha HDS Heater H-0402a and Naphtha Splitter Reboiler H-0405 and associated potential to emit. Calumet accepted the responsibility for the guarantee of NO_X emissions when firing above a manufacturer's design firing rate.

5. Conversion of Boiler #3 from the SO_2 emissions limitation and monitoring requirements of NSPS Ja, to the fuel gas H_2S limitations and monitoring requirements of NSPS Ja.

6. Removal of the requirements no longer necessary regarding the old sour water stripper unit that was taken out of service in 2006. The unit was removed from the site.

7. Removal of ambient air quality monitoring requirements. Requiring ambient air quality monitoring for SO_2 concentrations at Calumet is neither necessary nor appropriate because of the following:

a. The existing air quality is significantly below national ambient air quality standards;
b. The SO_2 emissions from Calumet are well monitored and limited; and
c. There are limited sources of SO_2 emissions which may affect ambient SO_2 concentrations in the area.

8. Removal of ability of Boiler #3 to burn Sour Water Stripper Overhead gas. The SWS overhead is burned in Boilers #1 and #2, and Calumet does not intend to burn SWS overhead in Boiler #3.

9. Taking certain reporting frequency obligations from quarterly to semiannual, based on the presence of prompt deviation reporting requirements in the required Title V for this facility and in most cases, an established compliance margin with underlying limits or requirements.

MAQP #2161-37 replaced MAQP #2161-36.

On 8/23/2022

Related to the Asphalt Upgrades Project-it requests the following changes:

1. Hot Oil Heater (H-1903) and the Hot Oil Heater (H-1904) while originally planned to operate on either natural gas and refinery fuel gas, will only operate on natural gas. The refinery fuel gas was not connected to these heaters. Modify the permit condition for these heaters to indicate they will only operate on natural gas.

2. Revise upward the assumptions for the VOC and H_2S concentrations which were originally used in the previous permit application. Since restarting the PMA Unit, Calumet has learned that the referenced H_2S and VOC concentration estimates for the PMA Unit's storage tanks and process vessels are higher than those assumptions, and the emissions need to be adjusted upward to accommodate the new information.

Related to the Refinery Reconfiguration Project requests the following changes:

3. In the August 4, 2021, Refinery Reconfiguration Project MAQP application that Calumet submitted to DEQ, Calumet indicated that it would install the HTU Fractionation Heater (H-1730) at the refinery as part of the proposed changes to the refinery's Hydrotreating Unit (HTU). However, Calumet has subsequently decided that the HTU Fractionation Heater (H-1730) will not be installed at the refinery. Therefore, the heater should be removed from the refinery's MAQP.

4. In the August 4, 2021, Refinery Reconfiguration Project MAQP application, Calumet indicated that it would transfer Tank #125 to MRL. However, Calumet will not transfer Tank #125 to MRL. Instead, the storage tank will remain in heavy liquids service at the refinery, with the maximum true vapor pressure of the tank's contents not exceeding 0.5 pounds per square inch-absolute (psia), as authorized by the refinery's MAQP. Therefore, the storage tank will not be removed from the refinery's MAQP.

5. In the August 4, 2021, Refinery Reconfiguration Project MAQP application, Calumet indicated that it would transfer the MHC Fractionator Feed Heater (H-4102) to MRL, but MRL would shut down the heater. However, MRL subsequently concluded that the MHC Fractionator Feed Heater (H-4102) would be required to operate in its Renewable Diesel Unit's (RDU's) fractionation process. Therefore, MRL permitted the MHC Fractionator Feed Heater (H-4102) in MAQP No. 5263-01 and changed its description to the "RDU Fractionator Feed Heater (H-4102)." This change impacts the current carbon monoxide (CO) and oxides of nitrogen (NOx) umbrella limits indicated in the refinery's MAQP.

6. In the August 4, 2021, Refinery Reconfiguration Project MAQP application, Calumet indicated the railcar unloading facilities for renewable feeds would be located at the refinery. However, the railcar unloading facilities for renewable feeds are to be located at the MRL Great Falls Renewable Fuels Plant instead. MRL permitted those facilities in MAQP No. 5263-01. Therefore, the renewable feed railcar unloading facilities should be removed from the refinery's MAQP.

7. In the August 4, 2021, Refinery Reconfiguration Project MAQP application, Calumet indicated the railcar loading facilities for renewable diesel would be located at the refinery. However, the railcar loading facilities for renewable diesel are to be located at the MRL Great Falls Renewable Fuels Plant instead. MRL permitted those facilities in MAQP No. 5263-01. Therefore, the renewable diesel railcar loading facilities should be removed from the refinery's MAQP.

8. Calumet will add piping, piping components (valves, flanges, connectors, etc.), and eductors (mixers) at the refinery to reduce the potential for the formation of ammonium carbonate salts in the refinery equipment that will process the RDU sour water stripper overhead stream. Specifically, this new equipment will provide the refinery with the capability to recirculate a liquid stream that will contact the RDU sour water stripper overhead stream, which is expected to minimize the chemical and physical mechanisms that promote the formation of ammonium carbonate salts. The new piping fugitive components will be incorporated into the refinery's leak detection and repair program, as applicable. However, note that most of the new components will contain only a small amount (<2 weight %) of VOC and a negligible amount of hazardous air pollutants. The potential to emit VOC emission rate for these new piping fugitive components is covered by the potential to emit VOC emission rate previously calculated for the additional piping fugitive components estimated to be installed at the refinery as part of the Refinery Reconfiguration Project.

MAQP #2161-38 replaced MAQP #2161-37.

D. Current Permit Action

On 02/09/2023, the Department received a request to modify MAQP #2161-38 for conditions which were incorporated from an application received on October 21, 2002. On October 21, 2002, to incorporate required elements from a Consent

Decree lodged on December 20, 2001. These elements were incorporated and issued in MAQP #2161-16 on March 19, 2003, and for each requirement were referenced as being required by the Consent Decree. Later permitting actions including MAQP #2161-19 issued on August 15, 2007, and MAQP #2161-24 issued on September 25, 2010, also incorporated additional Consent Decree items. The current permitting action requests the removal of the references to the Consent Decree. The requirements of the Consent Decree will be replaced with a standard reference for Montana Air Quality Permits using Administrative Rules of Montana (ARM) 17.8.749 - CONDITIONS FOR ISSUANCE OR DENIAL OF PERMIT. For a determination of which permit conditions were impacted by the removal of references to the Consent Decree, review MAQP #2161-38. The application also requests several minor corrections to permit conditions issued in recently permitted actions.

MAQP #2161-39 replaces MAQP #2161-38.

E. Response to Public Comments

Commentor	Draft Permit Section	Summarized Comment	DEQ Response
Calumet	II.C.2	Flare #2 (secondary flare) must maintain a water seal except during periods of startup, shutdown, or malfunction as defined in this permit. These periods of startup, shutdown, and malfunction shall not exceed 9 hours per year based on a 12-month rolling average (ARM 17.8.749).	Updated as Requested
Calumet	II.C.20	Calumet shall not combust fuel oil as defined in this permit in any combustion unit, except torch oil as defined in this permit may be used in the FCCU Regenerator during FCCU startups	Updated as Requested
Calumet	II.D.15.d	50 ppmvd on a 7-day rolling averaged at 0% O_2, ~~except for periods of hydrotreater outages~~. SO_2 emissions during periods of startup, shutdown, or malfunction of the FCCU shall not be used in determining compliance with the 7-day rolling average SO_2 emission limit, provided that during such periods Calumet implements good air pollution control practices to minimize SO_2 emissions.	Updated as Requested
Calumet	II.D.15.e	87 ppmvd on a 7-day rolling averaged at 0% O_2, ~~except for periods of hydrotreater outages~~. NOX emissions during periods of Startup, Shutdown, or Malfunction of the FCCU shall not be used in determining compliance with the 7-day rolling average NO_X emission limit, provided that during such periods Calumet implements good air pollution control practices to minimize NOX emissions.	Updated as Requested
Calumet	Section B.3	"CEMS" shall mean continuous emissions monitoring system.	Updated as Requested
		"Fuel Oil" shall mean any liquid fossil fuel with sulfur content of greater than 0.05% by weight.	
		"Shutdown" shall mean the cessation of operation of equipment for any purpose.	
		"Startup" shall mean the setting in operation of equipment for any purpose.	
		"Torch Oil" shall mean FCCU feedstock or light cycle oil that is combusted in the FCC regenerator to assist in starting up or restarting the FCCU.	

F. Additional Information

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

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the ARM and are available upon request from 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 is 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. Calumet shall also comply with the testing and monitoring 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.

4. Calumet 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.

5. ARM 17.8.110 Malfunctions. (2) 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.

6. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, 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 as to create a public nuisance.

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

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 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
8. ARM 17.8.221 Ambient Air Quality Standard for Visibility
9. ARM 17.8.222 Ambient Air Quality Standard for Lead
10. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

Calumet must maintain compliance with the applicable ambient air quality standards.

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

1. ARM 17.8.304 Visible Air Contaminants. (1) This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed on or before November 23, 1968, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes. (2) This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

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 are taken to control emissions of airborne particulate matter. (2) Under this rule, Calumet 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 17.8.322 Sulfur Oxide Emissions – Sulfur in Fuel. (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.

6. 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.

7. ARM 17.8.340 Standard of Performance for New Stationary Sources. This rule in conjunction with ARM 17.8.302, incorporates by reference 40 CFR Part 60. The owner or operator of any stationary source or modification, as defined and applied in 40 CFR Part 60, shall comply with the standards and provisions of 40 CFR Part 60, New Source Performance Standards (NSPS). The applicable NSPS Subparts include, but are not limited to:

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

   b. Subpart Dc – Standards of Performance for Small Industrial-Commercial Institutional Steam Generating Units for which construction, modification, or reconstruction is commenced after June 9, 1989. This Subpart applies to Boiler #3, Hot Oil Heater H-1903, and Hot Oil Heater H-1904.

   c. Subpart J – Standards of Performance for Petroleum Refineries. The provisions of this subpart are potentially applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants with a design capacity for sulfur feed of 20 long tons per day (LTD) or less. Regardless of applicability determinations, the following shall be considered affected units, as described per the Consent Decree:

      - FCCU regenerator: for CO and for SO_2, and
      - Heaters, boilers and flare (constructed or modified on or before May 14/2007).

      The following are noted as included as Subpart J applicable units:

      - Crude Unit #1 Atmospheric Tower Heater H-0101
      - Crude Unit #1 Vacuum Tower Heater H-0102
      - FCCU Catalyst Regenerator
      - FCCU Preheater H-0302
      - Reformer Heater H-0403
      - Alkylation Unit Deisobutanizer Reboiler Heater
      - Hydrogen Plant #1 Furnace H-1801
      - Tank #55, 110, 112, 130, 132, 133, 135, 137, 139, 140 Heaters
      - Hydrotreater Unit Kerosene Heater
      - HTU Heater H-1701
      - Boiler #1
      - Boiler #2

d. Subpart Ja – Standards of Performance for Petroleum Refineries for which Construction, Reconstruction or Modification Commenced After May 14, 2007. The provisions of this subpart potentially apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares and sulfur recovery plants.

e. The following are noted as included as Subpart Ja applicable units:

- Crude Unit #2 Atmospheric Tower Heater H-2101
- Crude Unit #2 Vacuum Tower Heater H-2102
- Naphtha HDS Heater H-0402a
- Naphtha Slitter Reboiler H-0405
- Hydrogen Plant #2 Furnace H-2815
- Hydrogen Plant #3 Reformer Heaters H-3815A and H-3815B (Once DEQ receives written notification that the emission sources have been transferred to MRI, they will no longer be regulated by this condition.)
- Tank #138 Heater
- Mild Hydrocracker Unit Combined Feed Heater H-4101 (Once DEQ receives written notification that the emission source has been transferred to MRI, it will no longer be regulated by this condition.)
- Mild Hydrocracker Unit Fractionator Feed Heater H-4102 (Once DEQ receives written notification that the emission source has been transferred to MRI, it will no longer be regulated by this condition.)
- Boiler #3
- Flare #1
- Flare #2
- Hot Oil Heater H-1903
- Hot Oil Heater H-1904

f. Subpart Kb – Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction or Modification Commenced After July 23, 1984.

g. Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture – shall apply to all asphalt storage tanks that process and store only non-roofing asphalts, and was constructed or modified since May 26, 1981.

The following are noted as included as Subpart UU affected units:

- Tanks #50, #102, #107, #139, #140, #55 (Once DEQ receives written notification that Tanks #50, #102, and

#140 have been transferred to MRI, the emission sources will no longer be regulated by this condition.)

h. Subpart VV – Standards of Performance for Equipment Leaks of Volatile Organic Compounds (VOC) in the Synthetic Organic Chemicals Manufacturing Industry, shall apply to this refinery as required by 40 CFR 60 Subpart GGG and 40 CFR 63 Subpart CC.

i. Subpart VVa - Standards of Performance for Equipment Leaks of VOC shall apply to this refinery as required by 40 CFR 60 Subpart GGGa.

j. Subpart GGG – Equipment Leaks of VOC in Petroleum Refineries. Affected units include the equipment components in the following process units:

- Crude Unit #1
- Fluid Catalytic Cracking Unit
- Hydrogen Plant #1
- HTU (Once DEQ receives written notification that the emission source has been reconfigured to increase capacity for the Refinery Reconfiguration Project, the emission source will no longer be regulated by this condition.)
- Polymer Modified Asphalt Unit

k. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006. Unless exempt, this standard applies to compressors, valves, pumps, pressure relief devices, sampling connection system, open-ended valves and lines, flanges, and connectors in the following units:

- Crude Unit #2
- Catalytic Reformer and Naphtha Units
- Hydrogen Plant #2
- Hydrogen Plant #3 (Once DEQ receives written notification that the emission source has been transferred to MRI, it will no longer be regulated by this condition.)
- HTU
- Mild Hydrocracker Unit (Once DEQ receives written notification that the emission source has been transferred to MRI, it will no longer be regulated by this condition.)
- NaHS Equipment Components
- Flare Gas Scrubber Components
- PMA Unit Piping Components

l. Subpart QQQ – VOC Emissions from Petroleum Refinery Wastewater Systems. Affected units subject to this subpart includes

the individual drain systems associated with the process units throughout the refinery.

8. ARM 17.8.341 Emissions Standards for Hazardous Air Pollutants, in conjunction with ARM 17.8.302, incorporates by reference 40 CFR Part 61.

   a. Subpart FF – National Emissions Standard for Benzene Waste Operations is applicable to the individual drain systems throughout the refinery as well as the wastewater treatment system.

9. ARM 17.8.342 Emissions Standards for Hazardous Air Pollutants for Source Categories, in conjunction with ARM 17.8.302, incorporates by reference 40 CFR Part 63 - National Emissions Standards for Hazardous Air Pollutants. Calumet shall comply with all applicable requirements of 40 CFR Part 63, maximum achievable control technology (MACT).

   a. Subpart A – General Provisions applies to all National Emission Standards for Hazardous Air Pollutants (NESHAP) source categories subject to a Subpart as listed below.

   b. Subpart Q - Calumet shall comply with 40 CFR 63 Subpart Q – NESHAP for Industrial Process Cooling Towers, during any timeframe in which 40 CFR 63 Subpart Q is applicable. This MACT is only applicable to industrial process cooling towers that are operated with chromium-based water treatment chemicals.

   c. Subpart R - NESHAP for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) applies as specified under Subpart CC, to the loading of gasoline at the gasoline truck loading rack and the gasoline railcar loading rack.

   d. Subpart CC - NESHAP Pollutants from Petroleum Refineries is potentially applicable to miscellaneous process vents, storage vessels, wastewater streams and treatment operations, equipment leaks from refining process units, gasoline loading racks, heat exchange systems, delayed coking units, pumps, compressors, pressure relief devices, sampling connection systems, valves and open-ended valve or lines, catalytic cracking unit and catalytic reformer unit catalyst regeneration vents, sulfur plant vents, emission points routed to a fuel gas system, and any flares receiving gas from that fuel gas system. Fence line monitoring is also required.

   e. Subpart UUU – NESHAP for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, shall apply to, but not be limited to, the FCCU and the Catalytic Reformer Unit.

   f. Subpart EEEE – NESHAP for Organic Liquids Distribution (non-gasoline) shall apply to, but not be limited to, Tank #1 (DEGME) and the naphtha loading racks.

g. Subpart FFFF – NESHAP for Miscellaneous Organic Chemical Manufacturing shall apply to, but not be limited to piping fugitive components, wastewater components, and transfer racks at the refinery that are used to load renewable products produced by the MRI-RDU.

h. Subpart DDDDD – NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, applies to all boilers and process heaters as specified in Subpart DDDDD.

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

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

b. ARM 17.8.402 Requirements. Calumet must demonstrate compliance with the ambient air quality standards based on the use of Good Engineering Practices (GEP) stack height.

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

a. 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. Calumet submitted the required application fee for this permit action.

b. 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 contaminants emitted during the previous calendar year.

c. 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. 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:

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

b. 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 Potential to Emit (PTE) greater than 25 tons per year of any pollutant. Calumet has a PTE greater than 25 tons per year of PM, NO_x, CO, VOC, and SO_2; therefore, an air quality permit is required.

c. 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.

d. 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.

e. 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. Calumet submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. Calumet posted public notice in the March 12, 2023, edition of the *Great Falls Tribune,* a newspaper of general circulation in Great Falls, Montana in Cascade County.

f. 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.

g. 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.

h. 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.

i. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving Calumet 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.

j. 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.

k. 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.

l. 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).

m. 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 17.8.752, 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.

n. 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.

o. 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:

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

b. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemption. 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 chapter would otherwise allow.

Calumet's existing petroleum refinery in Great Falls is defined as a "major stationary source" because it is a listed source with the PTE more than 100 tons of several pollutants (PM, SO_2, NO_X, CO, and VOC).

The action reviewed for MAQP #2161-37 does not trigger PSD review because the project emission increases (based on the potential to emit of each new or physically modified source and increases from existing non-modified, project impacted sources) are below the PSD major modification thresholds.

H. ARM 17.8, Subchapter 9 – Permit Requirements for Major Stationary Sources or Modifications Located within Nonattainment Areas, including, but not limited to:

a. ARM 17.8.904 When A Montana Air Quality Permit Required. This rule requires that major stationary sources or major modifications located within a nonattainment area must obtain an MAQP in accordance with the requirements of this subchapter, as well as the requirements of Subchapter 7.

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

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

PTE > 100 TPY of any pollutant;

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

PTE > 70 TPY of particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}) in a serious PM_{10} nonattainment area.

b. ARM 17.8.1204 Air Quality Operating Permit Program. (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 #2161-36 for Calumet, the following conclusions were made:

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

ii. The facility's PTE is greater than 10 TPY for a single HAP and greater than 25 TPY of combined HAPs.

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

iv. This facility is subject to NSPS requirements (including 40 CFR 60, Subparts A, J, Ja, Dc, Kb, UU, VV, VVa, GGG, GGGa, and QQQ).

v. This facility is subject to current NESHAP standards (including 40 CFR 61, Subparts, FF)

vi. This facility is subject to current NESHAP standards (including 40 CFR 63, Subparts A, R, CC, UUU, EEEE, FFFF, ZZZZ and DDDDD).

vi. This source is not a Title IV affected source.

vii. This facility is not a solid waste combustion unit.

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

Based on these facts, DEQ determined that Calumet is a major source of emissions as defined under Title V.

III. BACT Analysis

A BACT determination is required for each new or modified source. Calumet shall install BACT on the new or modified sources that is technically practicable and economically feasible. The current permitting action does not include any new or modified sources and therefore a BACT analysis was not required.

IV. Emission Inventory

The changes to the emission inventory and PSD analysis are shown from the original Asphalt Upgrades project application to the revised application are summarized below. The Asphalt Upgrades Project remains below PSD significance levels.

Asphalt Upgrade PSD Review				
Pollutant	**New Project-Only Emissions Increase[3] (TPY)**	**Original Project-Only Emissions Increase[3] (TPY)**	**PSD Significant Threshold (TPY)**	**Subject to PSD Review? (Yes/No)**
CO	5.26	5.26	100	No
NO_X	5.26	5.26	40	No
PM (filterable only)	0.26	0.26	25	No
PM_{10}	0.99	0.99	15	No
$PM_{2.5}$	0.98	0.98	10	No
SO_2	0.08	1.07	40	No
VOC	26.23	5.26	40	No
H_2S	7.77	0.28	10	No

Similarly, for the Refinery Reconfiguration Project the original emissions increases are shown versus the revised emissions increases versus the PSD thresholds. The primary change is the revised plan to no longer construct H-1701. The Refinery Reconfiguration Project remains below PSD significance levels.

Refinery Reconfiguration PSD Review				
Pollutant	**New Project-Only Emissions Increase[6] (TPY)**	**Original Project Only Emissions Increase[7] (TPY)**	**PSD Significant Threshold (TPY)**	**Subject to PSD Review (Yes/No)**
CO	6.37	11.05	100	No
NO_X	4.33	6.87	40	No
PM (filterable only)	0.08	0.23	25	No
PM10	0.31	0.93	15	No
PM2.5	0.31	0.93	10	No
SO2	0.85	1.53	40	No
VOC	18.27	23.38	40	No

Emission Unit: HTU Heater (H-1701)

Emission Unit Parameters	
Hourly Avg. Firing Rate	22.5 MMBtu/hr, HHV
Hourly Max. Firing Rate	22.5 MMBtu/hr, HHV
Fuel Type	Refinery Fuel Gas
Avg. Fuel Heating Value [1]	1,220 Btu/scf, HHV
Min. Fuel Heating Value [1]	907 Btu/scf, HHV
Avg. H_2S Concentration [2]	60 ppmv
Max. H_2S Concentration [2]	162 ppmv
Hours of Operation	8,760 hr/yr
Global Warming Potentials (GWP) [3]	
CO_2	1
CH_4	25
N_2O	298

Pollutants	Emission Factor	Hourly Avg. (lb/hr)	Hourly Max. (lb/hr)	Annual (tpy)
Criteria Pollutants [4]				
PM (filterable)	0.0019 lb/MMBtu	0.04	0.04	0.16
PM_{10} (filterable + condensable)	0.0075 lb/MMBtu	0.17	0.17	0.73
$PM_{2.5}$ (filterable + condensable)	0.0075 lb/MMBtu	0.17	0.17	0.73
NOx	0.07 lb/MMBtu	1.58	1.58	6.90
VOC	0.0054 lb/MMBtu	0.12	0.12	0.53
CO	0.039 lb/MMBtu	0.88	0.88	3.84
SO_2	- -	0.18	0.67	0.81
Greenhouse Gases [5]				
CO_2	130.07 lb/MMBtu	-	-	12,819
CH_4	0.0066 lb/MMBtu	-	-	0.65
N_2O	0.0013 lb/MMBtu	-	-	0.13
CO_2e	- -	-	-	12,874

Notes:

[1] Fuel heating value based on actual refinery fuel gas data (2015 calendar year data) determined to be a conservative representation of refinery fuel gas heating value for SO_2 emission calculations.

[2] NSPS Subpart Ja fuel gas H_2S limitations (162 ppmv on a 3-hour rolling average basis and 60 ppmv on a 365 successive calendar day rolling average basis).

[3] Values are EPA-designated global warming potential for specific greenhouse gases (40 CFR Part 98 Subpart A).

[4] PM (filterable), PM_{10}, $PM_{2.5}$, and VOC emission factors obtained from AP-42, Section 1.4, Table 1.4-2. Emission factors were corrected using typical natural gas heating value of 1,020 Btu/scf, as directed by footnote "a" of that table.

NOx emission factor is the unit's NOx emission limitation.

CO emission factor was derived based on the unit's hourly and annual CO emission rate limitations.

SO_2 emissions based on H_2S concentration of refinery fuel gas and 100% conversion of H_2S to SO_2.

[5] Emission factors obtained from 40 CFR Part 98 Subpart C, Tables C-1 and C-2 for fuel gas.

The Naphtha HDS Heater (H-0402a):

Emission Unit: Naphtha HDS Heater (H-0402a)

Emission Unit Parameters	
Hourly Avg. Firing Rate	13.6 MMBtu/hr, HHV
Hourly Max. Firing Rate	13.6 MMBtu/hr, HHV
Fuel Type	Refinery Fuel Gas
Avg. Fuel Heating Value [1]	1,220 Btu/scf, HHV
Min. Fuel Heating Value [1]	907 Btu/scf, HHV
Avg. H_2S Concentration [2]	60 ppmv
Max. H_2S Concentration [2]	162 ppmv
Hours of Operation	8,760 hr/yr
Global Warming Potentials (GWP) [3]	
CO_2	1
CH_4	25
N_2O	298

Pollutants	Emission Factor	Hourly Avg. (lb/hr)	Hourly Max. (lb/hr)	Annual (tpy)
Criteria Pollutants [4]				
PM (filterable)	0.0019 lb/MMBtu	0.03	0.03	0.11
PM_{10} (filterable + condensable)	0.0075 lb/MMBtu	0.10	0.10	0.44
$PM_{2.5}$ (filterable + condensable)	0.0075 lb/MMBtu	0.10	0.10	0.44
NOx	0.03 lb/MMBtu	0.41	0.41	1.79
VOC	0.0054 lb/MMBtu	0.07	0.07	0.32
CO	0.04 lb/MMBtu	0.54	0.54	2.38
SO_2	- -	0.11	0.40	0.49
Greenhouse Gases [5]				
CO_2	130.07 lb/MMBtu	-	-	7,748
CH_4	0.0066 lb/MMBtu	-	-	0.39
N_2O	0.0013 lb/MMBtu	-	-	0.08
CO_2e	- -	-	-	7,781

Notes:

[1] Fuel heating value based on actual refinery fuel gas data (2015 calendar year data) determined to be a conservative representation of refinery fuel gas heating value for SO_2 emission calculations.

[2] NSPS Subpart Ja fuel gas H_2S limitations (162 ppmv on a 3-hour rolling average basis and 60 ppmv on a 365 successive calendar day rolling average basis).

[3] Values are EPA-designated global warming potential for specific greenhouse gases (40 CFR Part 98 Subpart A).

[4] PM (filterable), PM_{10}, $PM_{2.5}$, and VOC emission factors obtained from AP-42, Section 1.4, Table 1.4-2. Emission factors were corrected using typical natural gas heating value of 1,020 Btu/scf, as directed by footnote "a" of that table.

NOx and CO emission factors based on burner vendor specifications.

SO_2 emissions based on H_2S concentration of refinery fuel gas and 100% conversion of H_2S to SO_2.

[5] Emission factors obtained from 40 CFR Part 98 Subpart C, Tables C-1 and C-2 for fuel gas.

Naphtha Splitter Reboiler H-0405:

Emission Unit: Naphtha Splitter Reboiler (H-0405)

Emission Unit Parameters	
Hourly Avg. Firing Rate	9.9 MMBtu/hr, HHV
Hourly Max. Firing Rate	9.9 MMBtu/hr, HHV
Fuel Type	Refinery Fuel Gas
Avg. Fuel Heating Value [1]	1,220 Btu/scf, HHV
Min. Fuel Heating Value [1]	907 Btu/scf, HHV
Avg. H_2S Concentration [2]	60 ppmv
Max. H_2S Concentration [2]	162 ppmv
Hours of Operation	8,760 hr/yr
Global Warming Potentials (GWP) [3]	
CO_2	1
CH_4	25
N_2O	298

Pollutants	Emission Factor	Hourly Avg. (lb/hr)	Hourly Max. (lb/hr)	Annual (tpy)
Criteria Pollutants [4]				
PM (filterable)	0.0019 lb/MMBtu	0.02	0.02	0.08
PM_{10} (filterable + condensable)	0.0075 lb/MMBtu	0.07	0.07	0.32
$PM_{2.5}$ (filterable + condensable)	0.0075 lb/MMBtu	0.07	0.07	0.32
NOx	0.03 lb/MMBtu	0.30	0.30	1.30
VOC	0.0054 lb/MMBtu	0.05	0.05	0.23
CO	0.04 lb/MMBtu	0.40	0.40	1.73
SO_2	- -	0.08	0.29	0.35
Greenhouse Gases [5]				
CO_2	130.07 lb/MMBtu	-	-	5,640
CH_4	0.0066 lb/MMBtu	-	-	0.29
N_2O	0.0013 lb/MMBtu	-	-	0.06
CO_2e	- -	-	-	5,664

Notes:

[1] Fuel heating value based on actual refinery fuel gas data (2015 calendar year data) determined to be a conservative representation of refinery fuel gas heating value for SO_2 emission calculations.

[2] NSPS Subpart Ja fuel gas H_2S limitations (162 ppmv on a 3-hour rolling average basis and 60 ppmv on a 365 successive calendar day rolling average basis).

[3] Values are EPA-designated global warming potential for specific greenhouse gases (40 CFR Part 98 Subpart A).

[4] PM (filterable), PM_{10}, $PM_{2.5}$, and VOC emission factors obtained from AP-42, Section 1.4, Table 1.4-2. Emission factors were corrected using typical natural gas heating value of 1,020 Btu/scf, as directed by footnote "a" of that table.

NOx and CO emission factors based on burner vendor specifications.

SO_2 emissions based on H_2S concentration of refinery fuel gas and 100% conversion of H_2S to SO_2.

[5] Emission factors obtained from 40 CFR Part 98 Subpart C, Tables C-1 and C-2 for fuel gas.

Reformer Heater H-0403:

Emission Unit: Reformer Heater (H-0403)

Emission Unit Parameters	
Hourly Avg. Firing Rate	24.2 MMBtu/hr, HHV
Hourly Max. Firing Rate	24.2 MMBtu/hr, HHV
Fuel Type	Refinery Fuel Gas
Avg. Fuel Heating Value [1]	1,220 Btu/scf, HHV
Min. Fuel Heating Value [1]	907 Btu/scf, HHV
Avg. H_2S Concentration [2]	60 ppmv
Max. H_2S Concentration [2]	162 ppmv
Hours of Operation	8,760 hr/yr
Global Warming Potentials (GWP) [3]	
CO_2	1
CH_4	25
N_2O	298

Pollutants	Emission Factor	Hourly Avg. (lb/hr)	Hourly Max. (lb/hr)	Annual (tpy)
Criteria Pollutants [4]				
PM (filterable)	0.0019 lb/MMBtu	0.05	0.05	0.20
PM_{10} (filterable + condensable)	0.0075 lb/MMBtu	0.18	0.18	0.79
$PM_{2.5}$ (filterable + condensable)	0.0075 lb/MMBtu	0.18	0.18	0.79
NOx	0.098 lb/MMBtu	2.37	2.37	10.40
VOC	0.0054 lb/MMBtu	0.13	0.13	0.57
CO	0.0824 lb/MMBtu	1.99	1.99	8.74
SO_2	- -	0.20	0.72	0.87
Greenhouse Gases [5]				
CO_2	130.07 lb/MMBtu	-	-	13,800
CH_4	0.0066 lb/MMBtu	-	-	0.70
N_2O	0.0013 lb/MMBtu	-	-	0.14
CO_2e	- -	-	-	13,860

Notes:

[1] Fuel heating value based on actual refinery fuel gas data (2015 calendar year data) determined to be a conservative representation of refinery fuel gas heating value for SO_2 emission calculations.

[2] NSPS Subpart Ja fuel gas H_2S limitations (162 ppmv on a 3-hour rolling average basis and 60 ppmv on a 365 successive calendar day rolling average basis).

[3] Values are EPA-designated global warming potential for specific greenhouse gases (40 CFR Part 98 Subpart A).

[4] PM (filterable), PM_{10}, $PM_{2.5}$, and VOC emission factors obtained from AP-42, Section 1.4, Table 1.4-2. Emission factors were corrected using typical natural gas heating value of 1,020 Btu/scf, as directed by footnote "a" of that table.

NOx and CO emission factors obtained from AP-42, Section 1.4, Table 1.4-1 (Small Boilers <100 MMBtu/hr, Uncontrolled). Emission factors were corrected using typical natural gas heating value of 1,020 Btu/scf, as directed by footnote "a" of that table.

SO_2 emissions based on H_2S concentration of refinery fuel gas and 100% conversion of H_2S to SO_2.

[5] Emission factors obtained from 40 CFR Part 98 Subpart C, Tables C-1 and C-2 for fuel gas.

V. Existing Air Quality

As of July 8, 2002, Cascade County is designated as an Unclassifiable/Attainment area for all criteria pollutants.

VI. Ambient Air Impact Analysis

The current ambient air quality status in the area is unclassifiable/attainment for all criteria pollutants. The current permitting action would not cause or contribute to an ambient air quality or increment exceedance.

VII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, DEQ conducted the following private property taking and damaging assessment.

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

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

VIII. Environmental Assessment

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

Calumet Montana Refinery, LLC

Final Environmental Assessment for

Montana Air Quality Permit #2161-39

Air Quality Bureau

APPLICANT: Calumet Montana Refining, LLC (Calumet)		
SITE NAME: Great Falls Refinery		
PROPOSED PERMIT NUMBER: Montana Air Quality Permit (MAQP) #2161-39		
APPLICATION RECEIVED: 02/09/2023		
APPLICATION DEEMED COMPLETE: 03/15/2023		
LOCATION: Lat/Long 47.523, -111.295		**COUNTY: Cascade**
PROPERTY OWNERSHIP: Private	**FEDERAL ____ STATE ____ PRIVATE _X___**	
EA PREPARER:	**Craig Henrikson**	
EA Draft Date: 03/21/2023	**EA Final Date: 04/24/2023**	**Permit Final Date: 05/10/2023**

COMPLIANCE WITH THE MONTANA ENVIRONMENTAL POLICY ACT

The Montana Department of Environmental Quality (DEQ) prepared this Environmental Assessment (EA) in accordance with requirements of the Montana Environmental Policy Act (MEPA). An EA functions to determine the need to prepare an Environmental Impact Statement (EIS) through an initial evaluation and determination of the significance of impacts associated with the proposed action. However, an agency is required to prepare an EA whenever, as here, statutory requirements do not allow sufficient time for the agency to prepare an EIS (Administrative Rules of Montana (ARM) 17.4.607(3)(c)). This document may disclose impacts over which DEQ has no regulatory authority.

COMPLIANCE WITH THE CLEAN AIR ACT OF MONTANA

The state law that regulates air quality permitting in Montana is the Clean Air Act of Montana (CAA), §§ 75-2-101, *et seq*., Montana Code Annotated (MCA). DEQ may not approve a proposed action contained in an application for an air quality permit unless the project complies with the requirements set forth in the CAA and the administrative rules adopted thereunder, ARMs 17.8.101 *et. seq*. The project is subject to approval by the DEQ Air Quality Bureau (AQB) as the proposed changes in the references to applicable requirements previously went through public notice and are subject to permitting as a modification (ARM 17.8.743). DEQ's approval of an air quality permit application does not relieve Calumet from complying with any other applicable federal, state, or county laws, regulations, or ordinances. Calumet is responsible for obtaining any other permits, licenses, or approvals (from DEQ or otherwise) that are required for any part of the proposed action. Any action DEQ takes at this time is limited to the pending air quality permit application currently before DEQ's AQB and the authority granted to DEQ under the Clean Air Act of Montana. This action is not indicative of any other action DEQ may take on any future (unsubmitted) applications made pursuant to any other authority (*e.g.* Montana's Water Protection Act). DEQ will decide whether to issue the pending air quality permit pursuant to the requirements of the CAA alone. DEQ may not withhold, deny, or impose conditions on the permit based on the information contained in this Environmental Assessment. § 75-1-201(4), MCA. Much of the background information provided in this EA was developed from permitting actions recently conducted at the Calumet Refinery and also at the newly permitted Montana Renewables site under MAQP #5263-00 and MAQP #5263-01.

SUMMARY OF THE PROPOSED ACTION

This Calumet air quality permit action has been assigned MAQP #2161-39.

All information included in the EA is derived from the permit application, discussions with the applicant, analysis of aerial photography, topographic maps, and other research tools. This permitting action is considered administrative in nature as it modifies how the Calumet Consent Decree (CD) is referenced within the MAQP but does not impact the underlying emission limits which were required by the CD.

Table 1: Proposed Action Details

Summary of Proposed Action	
General Overview	This action requests administrative changes to how the CD is referenced within the MAQP. The proposed changes are primarily removing the reference to the CD within the permit conditions and once the CD is terminated, the CD will no longer be valid, but the required conditions will remain.

Proposed Action Estimated Disturbance	
Disturbance	This action is administrative in nature and no disturbance would occur
Proposed Action	
Duration	**Construction:** No construction is proposed in the current action. **Operation Life:** Although equipment may have functional lives of 20 to 30 years depending on equipment maintenance efforts, the refinery has been operational since the 1920s and would be expected to remain operational as long as economic conditions are favorable.
Construction Equipment	The current permit action consists of changes to permit terms and conditions which do not necessitate any construction.
Personnel Onsite	**Operations:** No change in staff is necessary to accommodate the project.
Location and Analysis Area	**Location**: The proposed action is located at the Great Falls Refinery property whose street address is 1900 10th Street NE, Great Falls, Montana, 59404 and is shown in Figure 1 below. **Analysis Area**: The area being analyzed as part of this environmental review includes the immediate site area (Figure 1), as well as neighboring lands surrounding the analysis area, as reasonably appropriate for the impacts being considered.
Air Quality	The Draft EA will be attached to the Preliminary Determination Air Quality Permit which would include all enforceable conditions for operation of the emitting units. Any revisions to the EA would be addressed and included in the Final EA attached to DEQ's Decision.
Conditions Incorporated into the Proposed Action	The conditions included in the Department's Decision of the MAQP, set forth in Sections II.A-D.

Figure 1: Map of the Great Falls Refinery

PURPOSE AND BENEFIT FOR PROPOSED ACTION

DEQ's purpose in conducting this environmental review is to act upon Calumet's air quality permit application No. 2161-39 as described in the general overview in Table 1, above.

The benefits of the proposed action, if approved, include a permit which more accurately reflects the applicable requirements which will remain once the CD is terminated. The conditions required by the CD will remain, where required.

Authority to Calumet for operation would continue until the permit is revoked, either at the request of Calumet or by DEQ because of non-compliance with the conditions within the air quality permit.

REGULATORY RESPONSIBILITIES

DEQ must list any federal, state, or local, authorities that have concurrent or additional jurisdiction or environmental review responsibility for the proposed action and the permits, licenses, and other authorizations required. Calumet must conduct its operations according to the terms of its permit, the CAA, §§ 75-2-101, *et seq*., MCA, and ARMs 17.8.101, *et seq*.

Upon review of the air quality permit application, Calumet would need to modify their Title V Operating Permit with the proposed changes to make sure the Title V is reflective of the permitted equipment in their MAQP. The application submitted by Calumet, was a joint application and contains the information to update both the MAQP and the Title V permit.

Calumet must cooperate fully with and follow the directives of any federal, state, or local entity that may have authority over Calumet's Great Falls Refinery. These permits, licenses, and other authorizations may include: City of Great Falls, Cascade County Weed Control Board, Occupational

Safety and Health Administration (worker safety), DEQ AQB (air quality) and Water Protection Bureau (groundwater and surface water discharge; stormwater), and Montana Department of Transportation and Cascade County (road access).

EVALUATION AND SUMMARY OF POTENTIAL IMPACTS TO THE PHYSICAL AND HUMAN ENVIRONMENT IN THE AREA AFFECTED BY THE PROPOSED ACTION:

The impact analysis will identify and evaluate direct and secondary impacts. Direct impacts are those that occur at the same time and place as the action that triggers the effect. Secondary impacts mean "a further impact to the human environment that may be stimulated or induced by or otherwise result from a direct impact of the action." ARM 17.4.603(18). Where impacts are expected to occur, the impacts analysis estimates the duration and intensity of the impact. The duration of an impact is quantified as follows:

- **Short-term**: Short-term impacts are defined as those impacts that would not last longer than the proposed operation of the site.
- **Long-term**: Long-term impacts are defined as impacts that would remain or occur following shutdown of the proposed facility.

The severity of an impact is measured using the following:

- **No Impact**: There would be no change from current conditions.
- **Negligible Impact**: An adverse or beneficial effect would occur but would be at the lowest levels of detection.
- **Minor Impact**: The effect would be noticeable but would be relatively small and would not affect the function or integrity of the resource.
- **Moderate Impact**: The effect would be easily identifiable and would change the function or integrity of the resource.
- **Major Impact**: The effect would alter the resource.

1. TOPOGRAPHY, GEOLOGY AND SOIL QUALITY, STABILITY AND MOISTURE:

The Calumet site is located on the north-side of the Missouri River approximately 370 feet from the river's edge. The elevation is 3,323 feet as referenced by the nearest topographic map on the Montana DEQ GIS website.

The refinery is located on Pleistocene age glacial lake deposits, which overlie the consolidated Kootenai Formation. According to Calumet (email dated 8/31/2021 from Casey Mueller), these sediments are Deposits of Glacial Lake Great Falls with two subunits as an upper stratigraphic unit consisting predominantly of non-plastic fine sand and silt and a lower stratigraphic unit consisting mostly of laminated to non-laminated plastic clay and minor amounts of silt. Previous investigation activities at the facility have documented the presence of unconsolidated Pleistocene fluvial and lake deposits and various fill material at the surface and immediately beneath the Site. These surficial units have been encountered at variable depths across the site that range as much as 10 to 20 ft below ground surface. The Pleistocene deposits are generally

saturated but yield minimal quantities of water to wells because of their low hydraulic conductivity (email dated 8/31/2021 from Casey Mueller).

Underlying the Pleistocene glacial lake deposits is the Cretaceous-age Kootenai formation that has been differentiated into the fifth (upper) and fourth (lower) members. The fifth member of the Kootenai formation is encountered sitewide immediately beneath the surficial Pleistocene deposits and/or fill material and is distinguished by red-weathered mudstone that contains lenses and beds of brownish-gray and greenish-gray, cross-bedded, micaceous sandstone and light gray nodular limestone concretions. The lower part contains a dark-gray shale and lignite bed with a significant pre-angiosperm flora. The bottom of the Kootenai formation's upper member occurs at 60-100 feet below ground level near the Site. Groundwater in this unit beneath the site occurs under semi-confined conditions.

Direct Impacts: The information provided above is based on the information provided to DEQ for Montana Renewables Inc (MAQP #5263-00). project detailing the geology of the local area. No construction is proposed, and no deconstruction is required by the current permitting action.

Secondary Impacts: No secondary impacts to topography, geology, stability, and moisture would be expected.

2. WATER QUALITY, QUANTITY, AND DISTRIBUTION:

As mentioned above, the Missouri River is approximately 370 feet to the south. No wetlands have been identified on the site.

Direct Impacts: No construction is proposed, and no deconstruction is required by the current permit action. Calumet operates under water quality permit MTR00556. No fragile or unique water resources or values are known present. No impacts to water quality and quantity, which are resources of significant statewide and societal importance are expected.

Secondary Impacts: No secondary impacts to water quality, quantity, and distribution would be expected.

3. AIR QUALITY:

As of July 8, 2002, Cascade County is designated as an Unclassifiable/Attainment area for all criteria pollutants according to Title 40 Code of Federal Regulations (40 CFR) 81.327. An area was previously designated a nonattainment area for the pollutant carbon monoxide (CO). After a demonstration of compliance with the national ambient air quality standards (NAAQS), the area has been following a CO maintenance plan for 20 years to ensure the area does not regress.

Any stationary source falling under one of the 28 source categories listed in the "major stationary source" definition in ARM 17.8.801(22) would be a major stationary source if it emits, or has the potential to emit, 100 tons per year (TPY) or more of any regulated Prevention of Significant Deterioration (PSD) pollutant, except for greenhouse gases (GHG). The Great Falls Refinery is a "petroleum refinery", which is one of the 28 listed source categories and has the potential to emit 100 TPY or more of a regulated PSD pollutant. A proposed action is considered a

significant modification under the PSD rules if the proposed action's net emission increase exceeds the PSD significant thresholds under ARM 17.8.818. The current action is not a PSD action, as no net emissions increase greater than significant emissions rates is proposed. Likewise, the action would not be determined the cause or contributor to an ambient air quality standard or increment issue, based on the amount of change in allowable emissions. Further, any changes in actual emissions would not be expected to have a discernable impact on air quality.

Direct Impacts: No more than minor impacts would be expected.

Secondary Impacts: Impacts are to be restricted by an MAQP and therefore should have minor secondary air quality impacts.

4. VEGETATION COVER, QUANTITY AND QUALITY:

There are no known rare or sensitive plants or cover types present in the site area. No fragile or unique resources or values, or resources of statewide or societal importance, are present. Petroleum refining has been conducted at this site since the early 1920's. An air quality permit for the site was first issued in 1985. DEQ conducted research using the Montana Natural Heritage Program (MTNHP) website and ran the query titled "Environmental Summary Report" dated August 24, 2021. The proposed action is located at the existing Great Falls Refinery in an urban area where the vegetation is limited.

Direct Impacts: The current permit action does not involve new construction. The permit does not require deconstruction. No discernable impacts would be expected.

Secondary Impacts: Emissions are to be restricted by an MAQP and therefore should have minor secondary air quality impacts.

5. TERRESTRIAL, AVIAN AND AQUATIC LIFE AND HABITATS:

As described earlier in Section 4. Vegetation Cover, the area is represented by commercial and industrial operations. DEQ previously conducted research using the MTNHP website and ran the query titled "Environmental Summary Report" dated August 24, 2021 which produced the following species of concern (SOC): Spiny Softshell, Bald Eagle, Great Blue Heron, Golden Eagle, Black Crowned Night-Heron, Black Tern, Common Tern, Swift Fox, Horned Grebe, Ferruginous Hawk, Franklin's Gull, Piping Plover, Foster's Tern, Caspian Tern, American White Pelican, Common Loon, Trumpeter Swan, Harlequin Duck, Sedge Wren, Black-tailed Prairie Dog, Black-foot Ferret, and Gray-crowned Rosy-Finch. Many of these species listed as SOC have not been observed within the search polygon. The one exception noted is that Bald Eagles have been observed. However, avian populations are not likely to exist on the property due to the existing industrial nature of the property. Avian species may be in the proximity of the Great Falls Refinery due to the Missouri River.

Direct Impacts: The potential impact (including cumulative impacts) to terrestrial, avian and aquatic life and habitats would be negligible, due to the long-term industrial nature of the site.

Secondary Impacts: No secondary impacts to terrestrial, avian and aquatic life and habitats stimulated or induced would be expected.

6. UNIQUE, ENDANGERED, FRAGILE OR LIMITED ENVIRONMENTAL RESOURCES:

As described in Section 5 above, DEQ conducted a search using the MTNHP webpage. The search used a polygon that overlapped the site and produced the list of species of concern identified in Section 6.

Direct Impacts: Among the SOC from the MTNHP list, most are associated with the riverine habitat along the Missouri River, which is approximately 370 feet to the south of the refinery. These species would not be displaced by the proposed action as the site is completely industrial and has been since 1920. The potential impact (including cumulative impacts) to species (including Bald Eagles) would be negligible.

Secondary Impacts: The proposed action would have no secondary impacts to endangered species because the permit conditions are protective of human and animal health and all lands involved in the proposed action are currently used for industrial operations and would not change the effect to the environment.

7. HISTORICAL AND ARCHAEOLOGICAL SITES:

The Montana State Historic Preservation Office (SHPO) was previously contacted to conduct a file search for historical and archaeological sites within Section 1 Township 20 North, Range 3 East. SHPO provided a letter dated August 23, 2021, that indicated there have been twenty sites within the designated search location. Some of these sites have been registered, some were ineligible, some eligible and others undetermined. The type of sites that have been recorded include several identified as "historic residence" and "historic district." A site identified as "historic railroad" was noted as eligible. It is SHPO's position that any structure over fifty years of age is considered historic and is potentially eligible for listing on the National Register of Historic Places. If any structures are 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.

However, should structures need to be altered, or if cultural materials are inadvertently discovered during this proposed action, SHPO requests their office be contacted for further investigation.

Direct Impacts: Although the search by SHPO has identified some historical and archaeological sites, the project is not expected to impact any new locations that are not already in industrial activity. Therefore, no impacts to historical and archeological sites would be expected.

Secondary Impacts: No secondary impacts to historical and archaeological sites are anticipated since the proposed action and operation is located on land currently in industrial use.

8. SAGE GROUSE EXECUTIVE ORDER:

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

Direct Impacts: The proposed action is not located within Sage Grouse habitat, so no direct impacts would occur.

Secondary Impacts: No secondary impacts to sage grouse or sage grouse habitat would be expected since the proposed action is not located within Sage Grouse habitat.

9. AESTHETICS:

The site is in an area mostly surrounded by private property in industrial operation. Of the 1,280 acres in the larger MTNHP polygon, 1,095 acres are indicated as either private or unknown ownership. The proposed action would occur on private land. The nearest residents to the proposed action reside to the northwest at a distance of approximately 500 feet. There are other houses located directly east of the refinery site starting at about 850 feet from the eastern property boundary. It is not expected that the nearest residences to the proposed site would experience any noticeable change in noise levels.

Direct Impacts: The current permit action does not involve installation of new equipment and does not require deconstruction. No impacts would be expected.

Secondary Impacts: The current permit action does not involve installation of new equipment and does not require deconstruction. No impacts would be expected.

10. DEMANDS ON ENVIRONMENTAL RESOURCES OF LAND, WATER, AIR OR ENERGY:

The site is located in an area characterized by heavy industry and commercial businesses. The operation of the Great Falls Refinery generates fuel for consumers offsite as gasoline, diesel, and jet fuel.

Direct Impacts: Energy and electric demands would continue for the duration of the facility's lifetime at or near current levels. See the Air Quality and Water Quality sections of the EA to review the potential impacts from the proposed action regarding air and water resources.

Secondary Impacts: The current permit action does not involve installation of new equipment and does not require deconstruction. No impacts would be expected.

11. IMPACTS ON OTHER ENVIRONMENTAL RESOURCES:

The site is surrounded by commercial and industrial properties.

Direct Impacts: No other environmental resources have been identified in the area beyond

those discussed above. Hence, there is no impact to other environmental resources.

Secondary Impacts: No secondary impacts to other environmental resources are anticipated.

12. HUMAN HEALTH AND SAFETY:

The applicant would be required to adhere to all applicable state and federal safety laws. The access to the public would continue to be restricted to this property.

Direct Impacts: Negligible change in impacts to human health and safety are anticipated as a result of this project action. There are no emission increases associated with this permitting action.

Secondary Impacts: No secondary impacts to human health and safety are anticipated as a result of the proposed action.

13. INDUSTRIAL, COMMERCIAL AND AGRICULTURAL ACTIVITIES AND PRODUCTION:

The site is currently in heavy industrial use due to the refinery operation, with other adjacent industrial and commercial properties in the area. There is no agricultural activity at the site**.**

Direct Impacts: No impacts on the industrial, commercial, and agricultural activities and production in the area would be expected.

Secondary Impacts: No secondary impacts to industrial, commercial, and agricultural activities and production are anticipated.

14. QUANTITY AND DISTRIBUTION OF EMPLOYMENT:

There currently are approximately 186 permanent jobs located at the Great Falls Refinery.

Direct Impacts: No change in employment is expected, therefore, no impacts expected.

Secondary Impacts: No secondary impact is expected on long term employment from the proposed action because the same employee base would be used.

15. LOCAL AND STATE TAX BASE AND TAX REVENUES:

The proposed action would be expected to have negligible impacts on the local and state tax base and tax revenue.

Direct Impacts: The current permitting action does not authorize the construction of new emitting units. Any impacts to local and state tax base and revenue would be expected to be negligible.

Secondary Impacts: No secondary impacts to local and state tax base and tax revenues are anticipated.

16. DEMAND FOR GOVERNMENT SERVICES:

The proposed action is in a heavy industrial and commercial area.

Direct Impacts: Compliance review and assistance oversight by DEQ AQB would be conducted in concert with other area activity when in the vicinity. The proposed action would have only minor impacts on demand for government services, mainly through oversight by DEQ AQB.

Secondary Impacts: No secondary impacts are anticipated on government services with the proposed action.

17. LOCALLY ADOPTED ENVIRONMENTAL PLANS AND GOALS:

A review was also conducted of the City of Great Falls website on August 25, 2021. A zoning map was located, and the proposed action was determined to be on an I-2 Heavy Industrial Zone parcel. Additional review of the City's Planning page revealed a Growth Policy was completed in 2013. Other Planning documents were also viewed one of which was a Missouri River Urban Corridor Plan (Plan). This document was dated 2004. The Calumet property near the Missouri River is unlikely to be an area where the preservation of river frontage is addressed by the Plan.

Direct Impacts: Calumet's proposed action is on property which is already zoned as Heavy Industrial. No impacts from the proposed action would be expected relative to any locally adopted community planning goals.

Secondary Impacts: No secondary impacts to the locally adopted environmental plans and goals are anticipated as a result of the proposed action.

18. ACCESS TO AND QUALITY OF RECREATIONAL AND WILDERNESS ACTIVITIES:

The current site of the proposed action is in an area of industrial use. Recreation opportunities are located to the south of the proposed action via water-activities on the Missouri River. No wilderness areas or other recreational sites are in the vicinity.

Direct Impacts: There would be no impacts to the access to wilderness activities as a result of the proposed action. Recreationalists on the Missouri River or pedestrians along the river trail would experience no change in the normal average impacts from the refinery.

Secondary Impacts: No secondary impacts to access and quality of recreational and wilderness activities are anticipated as a result of the proposed action.

19. DENSITY AND DISTRIBUTION OF POPULATION AND HOUSING:

The proximity of the proposed action to the City of Great Falls would accommodate housing needs for workers.

Direct Impacts: The project would not add to the population or require additional housing, therefore, no impacts to density and distribution of population and housing are anticipated.

Secondary Impacts: No secondary impacts to density and distribution of population and housing are anticipated as a result of the proposed action.

20. SOCIAL STRUCTURES AND MORES:

Based on the required information provided by Calumet, DEQ is not aware of any native cultural concerns that would be affected by the proposed action on this existing refinery facility.

Direct Impacts: The proposed action is located on an existing industrial site, no disruption of native or traditional lifestyles would be expected, therefore, no impacts to social structure and mores are anticipated.

Secondary Impacts: No secondary impacts to social structures and mores are anticipated as a result of the proposed operations.

21. CULTURAL UNIQUENESS AND DIVERSITY:

Based on the required information provided by Calumet, DEQ is not aware of any unique qualities of the area that would be affected by the proposed action on this existing refinery facility.

Direct Impacts: No impacts to cultural uniqueness and diversity are anticipated from this project.

Secondary Impacts: No secondary impacts to cultural uniqueness and diversity are anticipated as a result of the proposed action.

22. PRIVATE PROPERTY IMPACTS:

The proposed action would take place on privately-owned land. The analysis done in response to the Private Property Assessment Act indicates no impact. DEQ does not plan to deny the application or impose conditions that would restrict the regulated person's use of private property so as to constitute a taking. Further, if the application is complete, DEQ must take action on the permit pursuant to § 75-2-218(2), MCA. Therefore, DEQ does not have discretion to take the action in another way that would have less impact on private property—its action is bound by a statute.

There are private residences in the area of the proposed action. The closest residence is located approximately 500 feet to the northwest from the western property boundary. Other residences are located approximately 850 feet directly to the east from the eastern property boundary.

23. OTHER APPROPRIATE SOCIAL AND ECONOMIC CIRCUMSTANCES:

Due to the nature of the proposed action, no further direct or secondary impacts are anticipated from this project.

ADDITIONAL ALTERNATIVES CONSIDERED:

No Action Alternative: In addition to the analysis above for the proposed action, DEQ is considering 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.

Other Ways to Accomplish the Action: DEQ is not aware of other ways to accomplish the specific administrative changes requested in the current permit action within the intent of this section.

If the applicant demonstrates compliance with all applicable rules and regulations as required for approval, the "no action" alternative would not be appropriate. Pursuant to, § 75-1-201(4)(a), (MCA) DEQ "may not withhold, deny, or impose conditions on any permit or other authority to act based on" an environmental assessment.

CUMULATIVE IMPACTS:

Cumulative impacts are the collective impacts on the human environment within the borders 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 preimpact statement studies, separate impact statement evaluation, or permit processing procedures.

This environmental review analyzes only the proposed action submitted by Calumet, which is the air quality permit regulating the emissions from the equipment as listed in the "proposed action" section, above.

There are other sources of industrial emissions in the vicinity. Collectively, these sources and the proposed action can all contribute to the ambient air quality. The proposed action would not be expected to have any discernable impact. No change in the EPA air quality designation would be expected. As of July 8, 2002, Cascade County was designated as an Unclassifiable/Attainment area for all criteria pollutants.

A review was also conducted of the City of Great Falls Growth Policy which appears to have been updated in 2013. Several elements which are addressed in the Growth Policy include provisions to guide land-use, transportation, economic development, housing needs, and population projections.

DEQ considered potential impacts related to this project and potential secondary impacts. Due to the limited activities in the analysis area, cumulative impacts related to this proposed action would be negligible.

PUBLIC INVOLVEMENT:

Scoping for this proposed action consisted of internal efforts to identify substantive issues and/or concerns related to the proposed action. Internal scoping consisted of internal review of the EA document by DEQ Air Permitting staff.

Internal efforts also included queries to the following websites/ databases/ personnel:
- Montana State Historic Preservation Office
- Montana DEQ
- Cascade County
- Montana Natural Heritage Program
- Montana Cadastral Mapping Program

A fifteen-day public comment period occurred along with the Preliminary Determination on MAQP #2161-39 and was posted to the DEQ website.

OTHER GOVERNMENTAL AGENCIES WITH JURSIDICTION:

The proposed action would be fully located on privately-owned land. All applicable local, state, and federal rules must be adhered to, which, at some level, may also include other local, state, federal, or tribal agency jurisdiction. Other Governmental Agencies which may have overlapping, or sole jurisdiction include but may not be limited to: City of Great Falls, Cascade County Commission or County Planning Department (zoning), Cascade County Weed Control Board, Occupational Safety and Health Administration (worker safety), DEQ AQB (air quality) and Water Protection Bureau (groundwater and surface water discharge; stormwater), DNRC (water rights), and MDT and Cascade County (road access).

NEED FOR FURTHER ANALYSIS AND SIGNIFICANCE OF POTENTIAL IMPACTS

Under ARM 17.4.608, DEQ is required to determine the significance of impacts associated with the proposed action. This determination is the basis for the agency's decision concerning the need to prepare an environmental impact statement and also refers to DEQ's evaluation of individual and cumulative impacts. DEQ is required to consider the following criteria in determining the significance of each impact on the quality of the human environment:

1. The severity, duration, geographic extent, and frequency of the occurrence of the impact.

   "Severity" is analyzed as the density of the potential impact while "extent" is described as the area where the impact is likely to occur. An example could be that a project may propagate ten noxious weeds on a surface area of 1 square foot. In this case, the impact may be a high severity over a low extent. If those ten noxious weeds were located over ten acres there may be a low severity over a larger extent.

   "Duration" is analyzed as the time period in which the impact may occur while "frequency" is analyzed as how often the impact may occur. For example, an operation that occurs throughout the night may have impacts associated with lighting that occur every night (frequency) over the course of the one season project (duration).

2. 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.

3. Growth-inducing or growth-inhibiting aspects of the impact, including the relationship or contribution of the impact to cumulative impacts.

4. The quantity and quality of each environmental resource or value that would be affected, including the uniqueness and fragility of those resources and values.

5. The importance to the state and to society of each environmental resource or value that would be affected.

6. Any precedent that would be set as a result of an impact of the proposed action that would commit the DEQ to future actions with significant impacts or a decision in principle about such future actions.

7. Potential conflict with local, state, or federal laws, requirements, or formal plans.

The significance determination is made by giving weight to these criteria in their totality. For example, impacts with moderate or major severity may be determined to be not significant if the duration of the impacts is considered to be short-term. As another example, however, moderate or major impacts of short-term duration may be considered to be significant if the quantity and quality of the resource is limited and/or the resource is considered to be unique or fragile. As a final example, moderate or major impacts to a resource may be determined to be not significant if the quantity of that resource is high or the quality of the resource is not unique or fragile.

Preparation of an EA is the appropriate level of environmental review under MEPA if statutory requirements do not allow sufficient time for an agency to prepare an environmental impact statement, pursuant to ARM 17.4.607. An agency determines whether sufficient time is available to prepare an environmental impact statement by comparing statutory requirements that establish when the agency must make its decision on the proposed action with the time required to obtain public review of an environmental impact statement plus a reasonable period to prepare a draft environmental review and, if required, a final environmental impact statement.

SIGNIFICANCE DETERMINATION

The severity, duration, geographic extent, and frequency of the occurrence of the primary, secondary, and cumulative impacts associated with the proposed action would be limited.

DEQ has not identified any significant impacts associated with the proposed action for any environmental resource. Approving Calumet's air quality permit application would not set precedent that commits DEQ to future actions with significant impacts or a decision in principle about such future actions.

DEQ's issuance of a modified MAQP to Calumet for this proposed operation also does not set a precedent for DEQ's review of other applications, including the level of environmental review. A decision of on the appropriate level of environmental review is made based on case-specific considerations of the criteria set forth in ARM 17.4.608.

DEQ does not believe that the proposed action has any growth-inducing or growth-inhibiting aspects or that it conflicts 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, the proposed state action is not predicted to significantly impact the quality of the human environment. Therefore, at this time, preparation of an EA is determined to be the appropriate level of environmental review under MEPA.

Environmental Assessment and Significance Determination Prepared By:

Craig Henrikson	**Air Quality Engineer**
Name	**Title**

EA Reviewed By:

Julie Merkel	**Permitting Services Section Supervisor**
Name	**Title**

References

Air Quality Permit Application
Response to Incompleteness
Montana State Historical Preservation Office (SHPO) Report Received August 25, 2021
Montana Natural Heritage Program (Website Search Downloads) Last Download Aug 15, 2021
Montana Cadastral GIS Layer – Through-Out Project Up Until Decision Issuance
Air Quality Bureau Permitted Source List-GIS Layer
Air Quality Permit MAQP #2885-01
Air Quality Permit MAQP #4176-00
Air Quality Permit MAQP #5174-00
Air Quality Permit MAQP #5263-01
City of Great Falls Website – Planning Documents
Wind Rose Information – Great Falls International Airport

24. ABBREVIATIONS and ACRONYMS

AQB – Air Quality Bureau
ARM - Administrative Rules of Montana
BACT – Best Available Control Technology
BMP - Best Management Practices
Calumet – Calumet Montana Refining, LLC
CAA – Clean Air Act of Montana
CFR - Code of Federal Regulations
CO - carbon monoxide
DEQ – Department of Environmental Quality
DNRC – Department of Natural Recourses and Conservation
EA – Environmental Assessment
EIS – Environmental Impact Statement
EPA - U.S. Environmental Protection Agency
FCAA Federal Clean Air Act
HTU – Hydrotreating Unit
MAQP – Montana Air Quality Permit
MCA – Montana Code Annotated
MEPA – Montana Environmental Policy Act
MHC – Mild Hydrocracker
MPDES - Montana Pollutant Discharge Elimination System
MTNHP - Montana Natural Heritage Program
NO_X - oxides of nitrogen
Plan - Missouri River Urban Corridor Plan
PM - particulate matter
PM_{10} - particulate matter with an aerodynamic diameter of 10 microns and less
$PM_{2.5}$ - particulate matter with an aerodynamic diameter of 2.5 microns and less
PPAA - Private Property Assessment Act
Program - Sage Grouse Habitat Conservation Program
PSD - Prevention of Significant Deterioration
RFG – Refinery Fuel Gas
SHPO - Montana State Historic Preservation Office
SOC - Species of Concern
SO_2 - sulfur dioxide
TPY – tons per year
U.S.C. - United States Code
VOC - volatile organic compound

Definitions are quantified as follows:

• Short-term: Short-term impacts are defined as those impacts that would not last longer than the proposed operation of the site.

• Long-term: Long-term impacts are defined as impacts that would remain or occur following shutdown of the proposed facility.

1. Severity describes the density at which the impact may occur. Levels used are low, medium, high.

    The severity of an impact 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.

2. Extent describes the land area over which the impact may occur. Levels used are small, medium, and large.

3. Duration describes the time period over which the impact may occur. Descriptors used are discrete time increments (day, month, year, and season).

4. Frequency describes how often the impact may occur.

5. Probability describes how likely the impact may occur.