DEQ
Montana Department
of Environmental Quality

Air, Energy & Mining Division

Date of Posting: December 31, 2025

Joe Dauner
Montana Renewables, LLC
MRL Great Falls Renewable Fuels Plant
1900 10th Street NE, Great Falls, MT 59404

Sent via email: joseph.dauner@calumetspecialty.com

RE: Final and Effective Montana Air Quality Permit #5263-03

Dear Mr. Dauner

Montana Air Quality Permit (MAQP) #5263-03 for the above-named permittee is deemed final and effective as of December 31, 2025, by the Montana Department of Environmental Quality (DEQ). All conditions of the Decision remain the same. A copy of final MAQP #5263-03 is enclosed.

The project constitutes an “energy development project,” as defined by § 75-2-103(9), Montana Code Annotated (MCA). Pursuant to the applicable requirements of § 75-2-213(1)(a), MCA, the MAQP is subject to appeal for 30 days after DEQ renders its decision. The Decision may be appealed to the Board of Environmental Review (Board). A request for a hearing must be filed by 11:59 PM Mountain Standard Time on January 14, 2026.

Procedures for Appeal: The applicant or a person who has provided DEQ with comments during the formal public comment period, and who is directly and adversely affected by DEQ’s Decision, may request a hearing before the Board. The request for a hearing is limited to the issues raised in those comments. The appeal must be filed by the date stated above. The request for a hearing must contain an affidavit setting forth the grounds for the request. The hearing will be held under the provisions of the Montana Administrative Procedures Act. Submit requests for a hearing to: Chairman, Board of Environmental Review, P.O. Box 200901, Helena, Montana 59620 or the Board Secretary: DEQBERSecretary@mt.gov.

For DEQ,

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

Montana Air Quality Permit #5263-03

Montana Renewables LLC
1900 10th Street NE
Great Falls, Montana 59404

Final and Effective Date:
December 31, 2025

MONTANA AIR QUALITY PERMIT

Issued to:	Montana Renewables LLC 1900 10th Street NE Great Falls, Montana 59404	MAQP: #5263-03 Application Received: 07/15/2025 Application Complete: 10/17/2025 Preliminary Determination: 11/14/2025 Department's Decision: 12/15/2025 Permit Final: 12/31/2025

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 renewable fuels plant sits on the site previously occupied by the Montana Calumet Refinery. A map of the site including the proposed changes is included in the Environmental Assessment attached to this permit. The current permit action footprint expands beyond the original parcel where MRL equipment is sited, and acreage descriptions have been revised to reflect the changes.

B. Current Permit Action

On July 15, 2025, the Montana Department of Environmental Quality - Air Quality Bureau (DEQ) received an application for modification of MAQP #5263-02. The proposed expansion would increase MRL's combined sustainable aviation fuel (SAF) and renewable diesel (RD) production capacity from the current 16,140 barrels per day (bpd) to 24,000 bpd on an annual average, with a daily maximum of 27,000 bpd. The project is herein referred to as the "MaxSAF™ Project".

The MaxSAF™ Project includes the addition of a renewable fuels unit (RFU) reactor, a new RFU heater, a new hydrogen plant (#5), a Water Conservation Unit associated with the existing pretreatment unit (PTU), several new storage tanks, a new rail/truck loadout for blended SAF, an on-site PTU wastewater pre-treatment system, associated piping systems, and a cogeneration plant.

For the existing heaters (H-4101, H-4102, H-3815A, H-3815B, and H-4601) and the new heaters (H-4103 and H-5801), and Co-gen turbine, MRL also requested to set lb/hr-based oxides of nitrogen (NOx) emission limits for startup, shutdown, and maintenance (SSM) periods. Heater H-4801 was also renamed as H-4601 within this action.

The existing Hydrogen Plant #3 would be modified to allow the use of RFU off-gas as a feedstock but not as a direct fuel source to produce hydrogen. No physical changes will be made to the existing reformer heaters (H-3815A, H-3815B) of Hydrogen Plant #3.

No additional physical changes will be made to other existing permitted emitting units. However, the maximum annual material throughputs to some units (e.g., tanks, loading processes, etc.) would change due to the proposed MaxSAF™ expansion, which are evaluated as non-modified units with potential emission increases.

Additionally, the application requests changes that are administrative in nature and are unrelated to the MaxSAF™ project. Specifically, MRL requested removal of Consent Decree (CD) (CIV-no 01-142LH) conditions and plantwide umbrella limits that were originally specific to the Calumet Montana Refining-Petroleum Refinery. It has since been determined that although the Calumet Montana Refining-Petroleum Refinery is considered the same source as MRL for Title V purposes, for Prevention of Significant Deterioration (PSD) purposes, they are considered separate sources; therefore, the limits should be administratively removed from the MRL MAQP and thereafter, also from the MRL Title V Operating Permit.

Section II: Conditions and Limitations

A. Emission Limitations

1. RFU 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 during steady state operation using ultra-low NOx burners (ULNBs) and monitored via CEMS including an O_2 analyzer and NOx analyzer. Steady state operation is defined as operation not included in startup, shutdown and maintenance (SSM) periods as defined in Section IV (ARM 17.8.752 and ARM 17.8.749).

   b. NOx emissions during SSM periods shall not exceed 2.10 lb/hr as averaged over the duration of the SSM period (ARM 17.8.752).

   c. 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).

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

   e. 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).

   f. 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).

g. $PM_{2.5}$ (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).

h. 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).

i. The annual average firing rate of H-4101 shall not exceed 54 MMBtu/hr (HHV) (ARM 17.8.752 and ARM 17.8.749).

j. 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).

k. H-4101 shall only combust natural gas and RFU off-gas (ARM 17.8.749).

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

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

n. MRL is prohibited from burning liquid fossil fuels in H-4101 with a sulfur content greater than 0.05% by weight (ARM 17.8.749).

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 during steady state operation and monitored via CEMS including an O_2 analyzer and NOx analyzer. Steady state operation is defined as operation not included in startup, shutdown and maintenance (SSM) periods as defined in Section IV (ARM 17.8.752 and ARM 17.8.749).

c. NOx emissions during SSM periods shall not exceed 7.24 lb/hr as averaged over the duration of the SSM period for the combined stack emissions (ARM 17.8.752).

d. 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.

e. 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).

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

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

h. MRL is prohibited from burning liquid fossil fuels in H-3815A and H-3815B with a sulfur content greater than 0.05% by weight (ARM 17.8.749).

3. Hydrogen Plant #4 (H-4601- Formerly identified as H-4801 in MAQP versions prior to #5263-03). 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 during steady state operation and monitored via CEMS including an O_2 analyzer and NOx analyzer. Steady state operation is defined as operation not included in startup, shutdown and maintenance (SSM) periods as defined in Section IV (ARM 17.8.752 and ARM 17.8.749).

b. NOx emissions during SSM periods shall not exceed 9.37 lb/hr as averaged over the duration of the SSM period (ARM 17.8.752).

c. 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).

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

e. H-4601 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).

f. H-4601 shall not combust RFU off-gas fuel containing H_2S in excess of 30 ppmv. Additionally, the heater shall not combust RFU 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).

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-4601 shall not exceed 213 MMBtu/hr (HHV) (ARM 17.8.749).

i. 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).

j. H-4601 shall only combust natural gas, PSA off-gas and RFU off-gas (ARM 17.8.749).

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

4. Tanks #301, #302, #303, #304, #305, #306, #307, #308, #309, #310, #311, #312, #313, #314, #0801, #4201, and #4202

a. MRL shall control VOC emissions from Tank #301, #302, #303, #305, #306, #307, #308, #309, #310, #311, #312, #313, #314 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 Tanks #4201 and #4202 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 kerosene/SAF or an equivalent material with equal or lower vapor pressure (ARM 17.8.749).

   g. Tanks #306, #307 and #308 shall only be used to store renewable kerosene or SAF or an equivalent material with equal or lower vapor pressure (ARM 17.8.749).

   h. Tanks ##309, #310 and #311 shall only be used to store renewable kerosene or SAF 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 or an equivalent material with equal or lower vapor pressure (ARM 17.8.749).

   j. Tank #4201and #4202 shall only be used to store wastewater produced by the PTU and/or the Water Conservation Unit (ARM 17.8.749).

5. Hot Oil Expansion Tanks (D-4203 and D-4204)

   MRL shall utilize proper equipment design and good operating practices to minimize VOCs from the Hot Oil Expansion Tanks (D-4203 and D-4204) (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 RFU 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. Tanks #29, #116 and #128 shall utilize a fixed roof with submerged fill to store renewable kerosene/SAF or material with an equivalent or lower vapor pressure (ARM 17.8.752).

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

    a. RFU 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 RFU 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 and Hydrogen Plant #5 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 RFU, Hydrogen Plant #4, Storage Tank, PTU wastewater components and MaxSAF™ project components (ARM 17.8.752 and ARM 17.8.749).

a. RFU “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 (40 CFR 60 Subpart QQQ). The RFU 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 and Hydrogen Plant #5 “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 and Hydrogen Plant #5 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 RFU 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 RFU 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.16 (ARM 17.8.749).

18. RFU Fractionator Feed Heater (H-4102)

    a. NOx emissions shall not exceed 0.04 lb/MMBtu (HHV) on a 1-hour average during steady state operation using ULNBs. Steady state operation is defined as operation not included in startup, shutdown and maintenance (SSM) periods as defined in Section IV (ARM 17.8.752 and ARM 17.8.749).

    b. NOx emissions during SSM periods shall not exceed 1.67 lb/hr as averaged over the duration of the SSM period (ARM 17.8.752).

    c. 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).

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

    e. 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).

    f. 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).

g. $PM_{2.5}$ (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).

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

i. The annual average firing rate of H-4102 shall not exceed 38 MMBtu/hr (HHV) (ARM 17.8.749).

j. 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).

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

l. H-4102 shall not combust RFU off-gas fuel containing H_2S in excess of 30 ppmv. Additionally, the heater shall not combust RFU 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).

m. 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, renewable diesel, SAF and blended SAF shall utilize submerged fill loading (ARM 17.8.749 and ARM 17.8.752).

21. Railcar loading of renewable naphtha shall utilize an existing vapor combustion unit maintained by Calumet Montana Refining (ARM 17.8.752).

22. Railcar loading of renewable naphtha from Tank #304 must comply with 40 CFR 60 Subpart Kb (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60 Subpart Kb).

23. 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).

24. The New Pretreatment Water Conservation Unit shall minimize VOC emissions through proper design and operation (ARM 17.8.752).

25. The new RFU Stripped Sour Water Recycling process shall minimize VOC emissions through proper design and operation (ARM 1.8.752).

26. Truck loading of the Heavy Fractions Water from the new Water Conservation Unit shall utilize submerged fill loading (ARM 17.8.752).

27. Low Pressure Boilers (LPB-1 and LPB-2)

    a. Each LPB boiler shall comply with 40 CFR 63 Subpart DDDDD (40 CFR 63 Subpart DDDDD, ARM 17.8.749 and ARM 17.8.342).

    b. Each LPB boiler shall not exceed an annual average firing rate of 2 MMBtu/hr (HHV) (ARM 17.8.752 and ARM 17.8.749).

    c. Each LPB boiler shall only be fired on ultra-low sulfur diesel (maximum sulfur content of 15 ppm) (ARM 17.8.749 and ARM 17.8.752).

    d. Each LPB boiler shall follow good combustion practices and follow the manufacturer's recommendations for maintenance and operation (ARM 17.8.749 and ARM 17.8.752).

28. Non-Emergency Generators (Gen-1 and Gen-2)

    a. Each non-emergency generator shall comply with 40 CFR 63 Subpart ZZZZ by meeting the requirement of 40 CFR 60 Subpart IIII (40 CFR

63 Subpart ZZZZ, 40 CFR 60 Subpart IIII, ARM 17.8.749, ARM 17.8.340, and ARM 17.8.342).

b. Each non-emergency generator shall only be fired on ultra-low sulfur diesel (maximum sulfur content of 15 ppm) (ARM 17.8.749 and ARM 17.8.752).

c. Each non-emergency generator shall be EPA Tier 4 certified (ARM 17.8.749 and ARM 17.8.752).

d. Each non-emergency generator shall follow good combustion practices and follow the manufacturer's recommendations for maintenance and operation (ARM 17.8.749 and ARM 17.8.752).

29. RFU Heater H-4103

a. NOx emissions shall not exceed 0.035 lb/MMBtu (HHV) on a 30-day rolling average basis during steady state operation and monitored via CEMS including an O_2 analyzer and NOx analyzer using ULNBs (ARM 17.8.752 and ARM 17.8.749). Steady state operation is defined as operation not included in startup, shutdown and maintenance (SSM) periods as defined in Section IV (ARM 17.8.749).

b. NOx emissions shall not exceed 3.08 lb/hr as measured over the duration of the SSM period (ARM 17.8.752).

c. 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 an average of three 1-hour runs (ARM 17.8.752 and ARM 17.8.749).

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

e. PM (filterable) emissions shall not exceed 0.0019 lb/MMBtu (HHV) on an average of three-1-hour runs (ARM 17.8.752 and ARM 17.8.749).

f. PM_{10} (filterable plus condensable) emissions shall not exceed 0.0075 lb/MMBtu (HHV) on an average of three-1-hour runs (ARM 17.8.752 and ARM 17.8.749).

g. $PM_{2.5}$ (filterable plus condensable) emissions shall not exceed 0.0075 lb/MMBtu (HHV) on an average of three-1-hour runs (ARM 17.8.752 and ARM 17.8.749).

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

i. VOC emissions shall not exceed 0.0054 lb/MMBtu (HHV) on an average of three-1-hour runs (ARM 17.8.752 and ARM 17.8.749).

j. The annual average firing rate of H-4103 shall not exceed 80 MMBtu/hr (HHV) (ARM 17.8.749).

k. 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).

l. H-4103 shall only combust pipeline quality natural gas and RFU off-gas (ARM 17.8.749).

m. H-4103 shall not combust RFU off-gas fuel containing H_2S in excess of 30 ppmv. Additionally, the heater shall not combust RFU 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).

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

30. Hydrogen Plant #5 Reformer Heater (H-5801). MRL shall comply with the following requirements:

    a. NOx emissions shall be controlled by an ULNB, selective catalytic reduction and shall not exceed 0.004 lb/MMBtu (HHV) on a 30-day rolling average basis during steady state operation and monitored via CEMS including an O_2 analyzer and NOx analyzer. Steady state operation is defined as operation not included in startup, shutdown and maintenance (SSM) periods as defined in Section IV (ARM 17.8.752 and ARM 17.8.749).

    b. NOx emissions shall not exceed 20.64 lb/hr (HHV) as measured over the duration of the SSM period (ARM 17.8.752).

    c. 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 an average of three 1-hour runs (ARM 17.8.752 and ARM 17.8.749).

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

    e. 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 0.0019 lb/MMBtu (HHV) on an average of three-1-hour runs.

ii. PM_{10} (filterable plus condensable) emissions shall not exceed 0.0075 lb/MMBtu (HHV) on an average of three-1-hour runs.

iii. $PM_{2.5}$ (filterable plus condensable) emissions shall not exceed 0.0075 lb/MMBtu (HHV) on an average of three-1-hour runs.

f. H-5801 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).

g. H-5801 shall not combust RFU off-gas fuel containing H_2S in excess of 30 ppmv. Additionally, the heater shall not combust RFU 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).

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

i. VOC emissions shall not exceed 0.0054 lb/MMBtu (HHV) on the average of three 1-hour runs (ARM 17.8.752 and ARM 17.8.749).

j. The annual average firing rate of H-5801 shall not exceed 469 MMBtu/hr (HHV) (ARM 17.8.749).

k. MRL shall comply with 40 CFR 63 Subpart DDDDD which requires the process heater to undergo tune-ups- as specified in 40 CFR 63.7540 (40 CFR 63, Subpart DDDDD, ARM 17.8.342 and ARM 17.8.749).

l. H-5801 shall only combust natural gas, PSA off-gas and RFU off-gas (ARM 17.8.749).

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

n. H-5801 shall not exceed 0.24 lb/MMBTU of PM emissions (HHV) (ARM 17.8.309 and ARM 17.8.749).

31. Cogeneration Plant Turbine Firing Natural Gas

a. NOx emissions shall be controlled by selective catalytic reduction and shall not exceed 0.035 lb/MMBtu (HHV) on a 30-day rolling average basis during steady state operation and monitored via CEMS including an O_2 analyzer and NOx analyzer. Steady state operation is defined as operation not included in startup, shutdown and maintenance (SSM) periods as defined in Section IV (ARM 17.8.752 and ARM 17.8.749).

b. NOx emissions shall not exceed 58.45 lb/hr (HHV) as measured over the duration of the SSM period including SCR warm up period (ARM 17.8.752).

c. MRL shall use good combustion practices and a continuous oxygen monitoring system and catalytic oxidation to control CO emissions which may not exceed 0.008 lb/MMBtu (HHV) on an average of three 1-hour runs (ARM 17.8.752 and ARM 17.8.749).

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

e. 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 0.0019 lb/MMBtu (HHV) on an average of three-1-hour runs.
   ii. PM_{10} (filterable plus condensable) emissions shall not exceed 0.0066 lb/MMBtu (HHV) on an average of three-1-hour runs.
   iii. $PM_{2.5}$ (filterable plus condensable) emissions shall not exceed 0.0066 lb/MMBtu (HHV) on an average of three-1-hour runs.

f. VOC emissions shall not exceed 0.0021 lb/MMBtu (HHV) on an average of three 1-hour runs (ARM 17.8.752 and ARM 17.8.749).

g. VOC emissions shall utilize an oxygen monitoring system and good combustion practices minimize VOC emissions (ARM 17.8.749 and ARM 17.8.752).

h. MRL shall only burn lower sulfur fuels including renewable naphtha or natural gas to minimize SO_2 emissions (ARM 17.8.749 and ARM 17.8.752).

i. Pursuant to ARM 17.8.322(5), the turbine shall not burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 ft3 of gaseous fuel, calculated as H_2S at standard conditions (or approximately 808 ppmv H_2S) (ARM 17.8.322(5) and ARM 17.8.749).

j. The Cogeneration Turbine shall not combust fuel gas containing fuel gas containing H_2S in excess of 10 ppmv on an annual average basis (ARM 17.8.749 and ARM 17.8.752).

k. The annual firing rate of the Cogen Plant Turbine shall not exceed 185 MMBtu/hr (HHV) ARM 17.8.749.

l. The Cogeneration Unit shall comply with 40 CFR 60 Subpart KKKK for Work Practice standards to minimize CO emissions during all times including startup, shutdown and malfunction (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60 Subpart KKKK).

   i. Pursuant to 40 CFR 60.4333(a), MRL will operate and maintain the stationary combustion turbine, air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

m. The Cogeneration Unit shall comply with 40 CFR 60 Subpart KKKK for Work Practice standards to minimize SO_2 emissions during all times including startup, shutdown and malfunction (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60 Subpart KKKK). The Cogeneration Unit shall comply with either (i) or (ii), and (iii) below:

   i. Pursuant to 40 CFR 60.4330(a)(1), MRL will not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 0.90 pounds per megawatt-hour gross output.

   ii. Pursuant to 40 CFR 60.4330(a)(2), MRL will not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input.

   iii. Pursuant to 40 CFR 60.4333(a), MRL will operate and maintain the stationary combustion turbine, air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

n. The Cogeneration Unit shall comply with 40 CFR 60 Subpart KKKK to minimize NOx emissions (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60 Subpart KKKK).

   i. Pursuant to 40 CFR 60.4320(a), NOx emissions will not exceed 25 ppm at 15 percent O_2 or 1.2 lb/MWh of useful output

   ii. Pursuant to 40 CFR 60.4333(a), MRL will operate and maintain the stationary combustion turbine, air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

o. The Cogeneration Unit shall comply with 40 CFR 63, Subpart YYYY to minimize formaldehyde emissions to limit the concentration of formaldehyde to 91 ppbvd or less at 15-percent O_2, except during turbine startup. The period of time for turbine startup is subject to the limits specified in the definition of startup in § 63.6175 (ARM 17.8.749, ARM 17.8.342 and 40 CFR 63, Subpart YYYY).

p. The Cogeneration Unit shall comply with 40 CFR 63, Subpart YYYY to maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer (ARM 17.8.749, ARM 17.8.342, and 40 CFR 63, Subpart YYYY).

q. The Cogeneration Unit shall comply with 40 CFR 63, Subpart YYYY for applicable testing, monitoring and reporting requirements (ARM 17.8.749, ARM 17.8.342 and 40 CFR 63, Subpart YYYY).

32. Cogeneration Plant Firing Renewable Naphtha

a. NOx emissions shall be controlled by selective catalytic reduction and shall not exceed 0.035 lb/MMBtu (HHV) on a 30-day rolling average basis during steady state operation and monitored via CEMS including an O_2 analyzer and NOx analyzer. Steady state operation is defined as operation not included in startup, shutdown and maintenance (SSM) periods as defined in Section IV (ARM 17.8.752 and ARM 17.8.749).

b. NOx emissions shall not exceed 61.67 lb/hr (HHV) as measured over the duration of the SSM period including SCR warm-up period and fuel switching period (ARM 17.8.752).

c. MRL shall use good combustion practices and a continuous oxygen monitoring system and catalytic oxidation to control CO emissions which may not exceed 0.008 lb/MMBtu (HHV) on an average of three 1-hour runs (ARM 17.8.752 and ARM 17.8.749).

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

e. 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 0.0043 lb/MMBtu (HHV) on an average of three-1-hour runs.
   ii. PM_{10} (filterable plus condensable) emissions shall not exceed 0.012 lb/MMBtu (HHV) on an average of three-1-hour runs.
   iii. $PM_{2.5}$ (filterable plus condensable) emissions shall not exceed 0.012 lb/MMBtu (HHV) on an average of three-1-hour runs.

f. VOC emissions shall not exceed 0.004 lb/MMBtu (HHV) on an average of three 1-hour runs (ARM 17.8.752 and ARM 17.8.749).

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

h. MRL shall only burn lower sulfur fuels including renewable naphtha or natural gas to minimize SO_2 emissions. Liquid fuel content shall contain no more than 30 ppm by weight of sulfur content (ARM 17.8.749 and ARM 17.8.752).

i. The Cogeneration Turbine shall not combust fuel gas containing fuel gas containing H_2S in excess of 10 ppmv on an annual average basis (ARM 17.8.749 and ARM 17.8.752).

j. The annual firing rate of the Cogen Plant Turbine shall not exceed 185 MMBtu/hr (HHV) ARM 17.8.749.

k. The Cogeneration Unit shall comply with 40 CFR 60 Subpart KKKK for Work Practice standards to minimize CO emissions during all times including startup, shutdown and malfunction (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60 Subpart KKKK).

    i. Pursuant to 40 CFR 60.4333(a), MRL will operate and maintain the stationary combustion turbine, air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

l. The Cogeneration Unit shall comply with 40 CFR 60 Subpart KKKK for Work Practice standards to minimize SO_2 emissions during all times including startup, shutdown and malfunction (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60 Subpart KKKK). The Cogeneration Unit shall comply with either (i) or (ii), and (iii) below:

    i. Pursuant to 40 CFR 60.4330(a)(1), MRL will not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 0.90 pounds per megawatt-hour gross output.

    ii. Pursuant to 40 CFR 60.4330(a)(2), MRL not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input.

    iii. Pursuant to 40 CFR 60.4333(a), MRL will operate and maintain the stationary combustion turbine, air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

m. The Cogeneration Unit shall comply with 40 CFR 63, Subpart YYYY to minimize formaldehyde emissions to limit the concentration of formaldehyde to 91 ppbvd or less at 15-percent O_2, except during turbine startup. The period of time for turbine startup is subject to the limits specified in the definition of startup in § 63.6175 (ARM 17.8.749, ARM 17.8.342 and 40 CFR 63, Subpart YYYY).

n. The Cogeneration Unit shall comply with 40 CFR 63, Subpart YYYY to maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer (ARM 17.8.749, ARM 17.8.342, and 40 CFR 63, Subpart YYYY).

o. The Cogeneration Unit shall comply with 40 CFR 63, Subpart YYYY for applicable testing, monitoring and reporting requirements (ARM 17.8.749, ARM 17.8.342 and 40 CFR 63, Subpart YYYY).

B. Testing Requirements

1. The RFU 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. Annual NOx CEMS RATA, and once every three years from date of last test, concurrent NOx and CO source testing. (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-4601) 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. Annual NOx CEMS RATA, and once every three years from date of last test, concurrent NOx and CO source testing (ARM 17.8.105 and ARM 17.8.106).

4. The RFU 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 18.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. Once every three years from date of last test, concurrent NOx and CO testing (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.19.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.e (ARM 17.8.749).

7. MRL shall sample and analyze the concentration (dry basis) of H_2S in the RFU 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 (ARM 17.8.749).

8. The NOx and O_2 CEMS on the RFU Combined Feed Heater (H-4101), Hydrogen Plant #3 Reformer Heaters (H-31815A/H-3815B), and Hydrogen Plant #4 Reformer Heater (H-4601) 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. The RFU Heater (H-4103) shall be tested for CO and NOx concurrently and the results submitted to DEQ in order to demonstrate compliance with the emission limits contained in Section II.A.29. 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 DEQ. H-4103 shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by DEQ, for NOx and CO, concurrently, and the results submitted to DEQ in order to demonstrate compliance with the NOx and CO emission limits contained in Section II.A.29. The NOx analyzer shall undergo an annual RATA (ARM 17.8.105, ARM 17.8.106 and ARM 17.8.749).

10. The Hydrogen Plant #5 Reformer Heater (H-5801) shall be tested for CO and NOx concurrently and the results submitted to DEQ in order to demonstrate compliance with the emission limits contained in Section II.A.30. 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 DEQ. H-5801 shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by DEQ, for NOx and CO, concurrently, and the results submitted to DEQ in order to demonstrate compliance with the NOx and CO emission limits contained in

Section II.A.30 depending upon fuel. The NOx analyzer shall undergo an annual RATA (ARM 17.8.105, ARM 17.8.106 and ARM 17.8.749).

11. The Hydrogen Plant #5 Reformer Heater (H-5801) shall be tested for PM $PM_{10}/PM_{2.5}$ emissions in order to demonstrate compliance with the emission limits contained in Section II.A.30. The initial testing shall occur within 180 days of startup of the heater based on EPA Reference Methods 5 or 201a and 202 (ARM 17.8.105, ARM 17.8.106 and 17.8.749).

12. The Co-gen Turbine shall be tested for CO and NOx concurrently and the results submitted to DEQ in order to demonstrate compliance with the emission limits contained in Section II.A.31 or Section II.A.32 depending upon fuel. 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 DEQ. The Co-gen turbine shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by DEQ, for NOx and CO, concurrently, and the results submitted to DEQ in order to demonstrate compliance with the NOx and CO emission limits contained in Section II.A.31 or Section II.A.32 depending upon fuel. The NOx analyzer shall undergo an annual RATA (ARM 17.8.105, ARM 17.8.106 and ARM 17.8.749).

13. The Co-gen Turbine shall be tested for PM/PM10/PM2.5 emissions in order to demonstrate compliance with the emission limits contained in Section II.A.31. The initial testing shall occur within 180 days of startup of the heater based on EPA Reference Methods 5 or 201a and 202. If natural gas is not planned for operation during the first 180 days, the testing requirement is waived until such time as a source test can be rescheduled (ARM 17.8.105, ARM 17.8.106 and 17.8.749).

14. The Co-gen Turbine shall be tested for PM/PM10/PM2.5 emissions in order to demonstrate compliance with the emission limits contained in Section II.A.32. The initial testing shall occur within 180 days of startup of the heater based on EPA Reference Methods 5 or 201a and 202. If renewable naphtha is not planned for operation during the first 180 days, the testing requirement is waived until such time as a source test can be rescheduled (ARM 17.8.105, ARM 17.8.106 and 17.8.749).

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

16. DEQ may require further testing (ARM 17.8.105).

C. Operational Reporting Requirements

1. MRL 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.

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 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 (RFU Combined Feed Heater (H-4101), Hydrogen Plant #3 Reformer Heaters (H-3815A and H-3815B), Hydrogen Plant #4 Reformer Heater (H-4601), RFU Fractionator Feed Heater (H-4102), and Hot Oil Heater (H-4201), H-4103, H-5801, and Cogen Turbine, and apply the appropriate emission factors on a lb/MMBtu basis to calculate the monthly emissions. MRL should total MMBtu's by whether each heater is in normal operation or whether it is in an SSM mode. The monthly emissions information for the calendar year shall be submitted annually DEQ along with the annual emission inventory (ARM 17.8.749).

3. MRL shall document for each of the heaters (RFU Combined Feed Heater (H-4101), Hydrogen Plant #3 Reformer Heaters (H-3815A and H-3815B), Hydrogen Plant #4 Reformer Heater (H-4601), RFU Fractionator Feed Heater (H-4102),), H-4103, H-5801, and Cogen Turbine by month the total hours that each heater is effectively operating in startup, shutdown or maintenance mode (SSM) to allow for a comparison against the theoretical non-steady state operational time assumed to develop the emission inventory (ARM 17.8.749).

4. MRL shall notify DEQ 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 DEQ, 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).

5. 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 DEQ and must be submitted to DEQ upon request. These records may be stored at a location other than the plant site upon approval by DEQ (ARM 17.8.749).

D. Notification

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

1. Startup dates of each of the new tanks #309, #310, #311, #312, #313, #314, #4202, and H-4204, within 15 working days of the startup date of each tank.

2. Startup dates of the new Water Conservation Unit, Heavy Fractions loading, new PTU Wastewater Treatment Plant and new RFU Stripped Source Water Recycling

Process, within 15 working days of the startup date of each process.

3. Startup dates of heaters H-4103, H-5801 and Cogeneration Plant, within 15 working days of the startup of each process.
4. Initial startup date of Low Pressure Boiler-LPB-1 and Low Pressure Boiler-LPB-2, within 15 working days of the startup date of each..

SECTION III: General Conditions

A. Inspection – MRL 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 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 DEQ's decision may request, within 15 days after DEQ 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 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 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).

SECTION IV: Startup, Shutdown and Maintenance (SSM) Mode Definitions

MRL shall utilize the following descriptions to determine when the heaters are in a startup, shutdown or maintenance mode. All other times shall be considered part of normal, steady-state operation. These SSM limits specifically apply to NOx emission limit compliance demonstrations. (ARM 17.8.749).

A. H-4103 SSM Definitions
Conditions related to SSM for H-4103 are identified as described below (ARM 17.8.749).

1. Startup Beginning
- Startup begins when fuel combustion is initiated in the unit as verified by the CEMs. Burner pilots are exempt.

2. Startup End (all the following permissives must be met) Startup ends after all 3 of the criteria have been met for 60 minutes and/or the unit has met the normal operational emissions target on an hourly basis.
- The normal heater firing rate is achieved
- The firebox outlet O_2 is <4%.
- The reactor outlet temperature is on operational specification or target for this startup.

3. Shutdown Beginning (all the following permissives must be met)
- The shutdown begins when the Operator begins the planned or emergency shutdown procedure.

4. Shutdown End
- Shutdown ends when fuel combustion ceases in the unit as verified by the CEMs. Burner pilots are exempt.

5. Maintenance Periods
- SSM limits apply during periods of maintenance for the heater equipment while the unit is operating.

B. H-5801 SSM Definitions
Conditions related to SSM for H-5801 are identified as described below (ARM 17.8.749).

1. Startup Beginning
- Startup begins when fuel combustion is initiated in the unit as verified by the CEMs. Burner pilots are exempt.
- SCR startup is when ammonia injection begins. Ammonia injection begins when the downstream SCR temperature is above 550 °F.

2. Startup End (all the following permissives must be met).
- Startup ends after all 4 of the criteria have been met for 60 minutes and/or the unit has met the normal operational emissions target on an hourly basis.
- The firebox outlet O_2 is <4%.
- The PSA is yielding vent gas to the burners at a steady state.
- The unit is yielding hydrogen.
- Startup ends 60 minutes after the initiation of SCR ammonia injection or when complete reaction control is achieved.

3. Shutdown Beginning (all the following permissives must be met)
- The shutdown begins when the operator begins the planned or emergency shutdown procedure.

4. Shutdown End
- Shutdown ends when fuel combustion ceases in the unit as verified by the CEMs. Burner pilots are exempt.

5. Maintenance Periods
- SSM limits apply during periods of maintenance for the heater and SCR equipment while the unit is operating.

C. Cogeneration Plant Turbine Definitions

Conditions related to SSM for the Cogeneration Turbine are identified as described below (ARM 17.8.749).

1. Startup Beginning
- Startup begins when fuel combustion is initiated in the unit as verified by the CEMs.
- SCR startup is when ammonia injection begins. Ammonia injection begins when the downstream SCR temperature is above 550 °F.
- Burner pilots are exempt.

2. Startup End
- Startup ends 60 minutes after the initiation of SCR ammonia injection or when complete reaction control is achieved.

3. Fuel Switching and Tuning
- Fuel Switching means transferring from burning natural gas to burning renewable naphtha or transferring from burning renewable naphtha to natural gas.
- SSM limits apply during combustion tuning for regulatory and operational targets for good combustion practices.

4. Shutdown Beginning
- The shutdown begins when the Operator begins the planned or emergency shutdown procedure.

5. Shutdown End
- Shutdown ends when fuel combustion ceases in the unit as verified by the CEMs.
- Burner pilots are exempt.

6. Maintenance Periods
   - SSM limits apply during periods of maintenance for the SCR equipment while the unit is operating.

D. H-4101 SSM Definitions
Conditions related to SSM for H-4101 are identified as described below (ARM 17.8.749).

1. Startup Beginning
   - Startup begins when fuel combustion is initiated in the unit as verified by the CEMs. Burner pilots are exempt.

2. Startup End (all of the following permissives must be met) Startup ends after all 3 of the criteria have been met for 60 minutes and/or the unit has met the normal operational emissions target on an hourly basis.
   - The normal heater firing rate is achieved
   - The firebox outlet O_2 is <4%.
   - The reactor outlet temperature is on operational specification or target for this startup.

3. Shutdown Beginning (all of the following permissives must be met)
   - The shutdown begins when the Operator begins the planned or emergency shutdown procedure.

4. Shutdown End
   - Shutdown ends when fuel combustion ceases in the unit as verified by the CEMs. Burner pilots are exempt.

5. Maintenance Periods
   - SSM limits apply during periods of maintenance for the heater equipment while the unit is operating.

E. H-4102 SSM Definitions
Conditions related to SSM for H-4102 are identified as described below (ARM 17.8.749).

1. Startup Beginning
   - Startup begins when fuel combustion is initiated in the unit as verified by the CEMs. Burner pilots are exempt.

2. Startup End (all of the following permissives must be met) Startup ends after all 3 of the criteria have been met for 60 minutes and/or the unit has met the normal operational emissions target on an hourly basis.
   - The normal heater firing rate is achieved
   - The firebox outlet O_2 is <4%.
   - The reactor outlet temperature is on operational specification or target for this startup.

3. Shutdown Beginning (all the following permissives must be met)

- The shutdown begins when the Operator begins the planned or emergency shutdown procedure.

4. Shutdown End
- Shutdown ends when fuel combustion ceases in the unit as verified by the CEMs. Burner pilots are exempt.

5. Maintenance Periods
- SSM limits apply during periods of maintenance for the heater equipment while the unit is operating.

F. H-3815A and H-3815B SSM Definitions
Conditions related to SSM for H-3815A and H-3815B are identified as described below (ARM 17.8.749).

1. Startup Beginning
- Startup begins when fuel combustion is initiated in the unit as verified by the CEMs. Burner pilots are exempt.

2. Startup End (all of the following permissives must be met) Startup ends after all 3 of the criteria have been met for 60 minutes and/or the unit has met the normal operational emissions target on an hourly basis.
- The firebox outlet O_2 is <4%.
- The PSA is yielding vent gas to the burners at a steady state.
- The unit is yielding hydrogen

3. Shutdown Beginning (all the following permissives must be met)
- The shutdown begins when the Operator begins the planned or emergency shutdown procedure.

4. Shutdown End
- Shutdown ends when fuel combustion ceases in the unit as verified by the CEMs. Burner pilots are exempt.

5. Maintenance Periods
- SSM limits apply during periods of maintenance for the heater equipment while the unit is operating.

G. H-4601 SSM Definitions
Conditions related to SSM for H-4601 are identified as described below (ARM 17.8.749).

1. Startup Beginning
- Startup begins when fuel combustion is initiated in the unit as verified by the CEMs. Burner pilots are exempt.

2. Startup End (all the following permissives must be met) Startup ends after all 3 of the criteria have been met for 60 minutes and/or the unit has met the normal operational emissions target on an hourly basis.
- The firebox outlet O_2 is <4%.

- The PSA is yielding vent gas to the burners at a steady state.
- The unit is yielding hydrogen.

3. Shutdown Beginning (all of the following permissives must be met)

- The shutdown begins when the Operator begins the planned or emergency shutdown procedure.

4. Shutdown End

- Shutdown ends when fuel combustion ceases in the unit as verified by the CEMs. Burner pilots are exempt.

5. Maintenance Periods

- SSM limits apply during periods of maintenance for the heater equipment while the unit is operating.

Montana Air Quality Permit (MAQP) Analysis
Montana Renewables LLC.
MAQP #5263-03

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 supplies hydrogen feedstock to the Renewable Fuels Unit (RFU)

- Hydrogen Plant #4 Reformer Heater (H-4601)
- Piping fugitive components and
- Wastewater components

Previously permitted tanks storing either renewable feed or renewable fuels

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

MRL also operates the following existing equipment transferred from CMR

RFU 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 RFU 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 also shares 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 equipment related to Renewable Kerosene and Sustainable Aviation Fuel Production and other Design Changes.

Existing RFU side stripper for renewable kerosene production.

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

Process vessels in the RFU to perform filtration, coalescence and drying of renewable kerosene.

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.

Low Pressure Boilers
LPB-1
LPB-2

Non-emergency Generators
Gen-1

Gen-2

Small Diesel Storage Tanks (4)

Added Under MAQP #5263-03 (MaxSAF Project as New Equipment

Within the Renewable Fuels Unit (RFU)
    New Isomerization Reactor
    New RFU Heater H-4103

New Hydrogen Plant #5
    New Reformer Heater H-5801

Water Conservation Unit
New Wastewater Storage Tank #4202

New Renewable Fuels-related Storage Tanks
    Three (3) new renewable feed storage tanks #312, #313 and #314
    Three (3) new renewable kerosene/SAF tanks #309, #310 and #311

New PTU Wastewater Pretreatment System

Cogeneration Plant
    185 MMBtu/hr Turbine

Added Under MAQP #5263-03 as Modifications/Service Changes

Switch service for Tanks #29, #128 and #305 to allow renewable kerosene/SAF fuel service or an equivalent or lower vapor pressure.
Switch service for Tanks #306, #307 and #308 to renewable kerosene/SAF service or an equivalent or lower vapor pressure.

Truck loadout for blended SAF from Tank #309

The existing Hydrogen Plant #3 will be modified to allow the use of RFU off-gas as a raw material into the reactor/plant but is not introduced as fuel.

B. Source Description

The equipment described above operates at the MRL Great Falls Renewable Fuels Plant, which is adjacent to the CMR Great Falls Refinery. MRL operates as a subsidiary to Calumet Specialty Products Partners, L.P., as does CMR. The renewable equipment operating at the site is not a petroleum refinery and the numerous regulatory requirements for petroleum refineries do not apply to any of the new or transferred equipment operating under MAQP #5263.

C. Permit History

MAQP #5263-00 was issued on October 26, 2021. The proposed project allowed MRI to construct and operate a renewable diesel plant with a projected capacity of 15,000 barrels per day (bpd). Most of the equipment used for the renewable diesel plant was transferred from the existing CMR petroleum refinery assets with additional equipment also permitted for the new facility.

MAQP #5263-01 was issued on July 7, 2022. On April 26, 2022, the 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 was submitted under the name Renewable Feed Flexibility Project. The primary change in the plant design entailed 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. The additional wastewater generation also required 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, kerosene and a sustainable aviation fuel were added as products produced from the renewable fuels unit. These two new planned products also required 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. MAQP #5263-01 replaced MAQP #5263-00.

MAQP #5263-02
On August 31, 2023, DEQ received an application to modify MAQP #5263-01. Since the last MAQP was issued on July 7, 2022; the overall facility design has evolved. MRL operates one existing Renewable Diesel Unit (RDU) Combined Feed Heater and one existing RDU Fractionator Feed Heater, identified as H-4101 and H-4102 respectively, in MAQP #5263-01. The annual average firing rates of H-4101 and H-4102 are permitted not to exceed 25 one million British thermal units (MMBtu)/hour (hr) and 30 MMBtu/hr, respectively. MRL proposed to return the two heaters to the firing rates that were permitted when the heaters were part of CMR. No physical changes have been made to either heater, and H-4101 and H-4102 would be returned to their original firing rates of 54 MMBtu/hr, and 38 MMBtu/hr, respectively.

MRL also proposed to add two diesel-fired LP boilers, identified as, LPB-1 and LPB-2, which will be used for steam generation to heat rail cars that supply materials to the RDU. Each LP boiler will have a maximum heat input capacity of 2.2 MMBtu/hr. The two LP boilers will be trailer-mounted, and each trailer will be equipped with one diesel-fired non-emergency generator (Gen-1 and Gen-2). Each generator will be powered by an EPA Tier 4 certified engine with a maximum rated power capacity of 12.3 horsepower (hp).

MRL also proposed to add four small diesel fuel storage tanks to fire the two low pressure boilers and two non-emergency generators. **MAQP #5263-02** replaced MAQP #5263-01

D. Current Permit Action

On July 15, 2025, the Montana Department of Environmental Quality- Air Quality Bureau (DEQ) received an application for a modification to MAQP #5263-02. The proposed expansion would increase MRL's combined sustainable aviation fuel (SAF) and renewable diesel (RD) production capacity from the current 16,140 barrels per day (bpd) capacity to

24,000 bpd on an annual average, with a daily maximum of 27,000 bpd. The project is herein referred to as the "MaxSAF™ Project".

The MaxSAF™ Project include additions of an additional renewable fuel unit (RFU) reactor, a new RFU heater, a new hydrogen plant, a Water Conservation Unit associated with the existing pretreatment unit (PTU), several new storage tanks, a new rail/truck loadout for blended SAF, an on-site PTU wastewater pre-treatment system, associated piping systems, and a cogeneration plant.

For the existing heaters (H-4101, H-4102, H-3815A, H-3815B, and H-4601) and the new heaters (H-4103 and H-5801), and the Co-gen Turbine, MRL also requested to set lb/hr-based NOx emission limits for startup, shutdown, and malfunction (SSM) periods. The current lb/MMBtu-based NOx emission limits would only apply to normal operations of the heaters. Heater H-4801 was also renamed as H-4601 within this action.

The exiting Hydrogen Plant #3 would be modified to allow the use of RFU off-gas as a feedstock (not fuel) to produce hydrogen. No physical changes will be made to the existing reformer heaters (H-3815A, H-3815B) of Hydrogen Plant #3.

No additional physical changes will be made to other existing permitted emission units. However, the maximum annual material throughputs to some units (e.g., tanks, loading processes, etc.) would change due to the proposed MaxSAF™ expansion, which are evaluated as non-modified units with potential emission increases.

Additionally, the application also requests changes that are administrative in nature and are unrelated to the MaxSAF™ project. Specifically, MRL requested removal of Consent Decree (CD) (CIV-no 01-142LH) conditions and plantwide umbrella limits that were originally specific to the Calumet Montana Refining- Petroleum Refinery. It has since been determined that although the Calumet Montana Refining-Petroleum Refinery is considered the same source for Title V Purposes, for Prevention of Significant Deterioration (PSD) purposes, they are considered separate sources; therefore, the limits should be administratively removed from the MRL MAQP.

E. Response to Public Comments

DEQ received comments from MRL, and comments from two commenters from the general public. DEQ responses to MRL are shown below in Table I.E.1. Responses to comments from the general public are shown further below in Table I.E.2.

Comments Received from MRL

Table I.E.1

Reference to PD	Comment	DEQ Response
Condition II.A.1, Page 4	Please correct RD off-gas to RFU off-gas	Corrected as requested
Condition II.A.1, Page 6	For condition 4.f on page 6, please update tank 305 with the updated BACT for the increased emissions from the	Corrected as requested

	change in service requested to include Renewable Jet fuel and/or less volatile renewable fuels or feedstocks. Please update condition 4.F to reflect the product flexibility.	
Condition II.A.1, page 12,15, 17 and 18	Conditions 29.c, 31.c&f and 32c&f should show compliance and testing "on an average of three 1-hour runs".	In response to the averaging period comment for each of the new heaters (H-4103, H-5801 and Cogen Plant), DEQ has discussed with MRL the inconsistencies with the BACT averaging periods submitted. It is clear that multiple authors contributed to the BACT submittal resulting in use of similar but not identical references for averaging periods. DEQ has clarified in the BACT analysis; BACT permit conditions, and summary tables that "1-hour average" is determined by the average of three 1-hour runs which historically matches with regulatory compliance testing. Similarly, where the description 3-hour average was used, this is determined by the average of three 1-hour runs. Permit conditions have been clarified to confirm the averaging period demonstrations.
Condition II.A.1, Page 22	Please remove Hot Oil heater H-4201 from condition C.3 on page 22 from the list of heaters subject to SSM and subsequent recordkeeping and reporting requirements.	Corrected as requested. Also removed reference to H-4201 in the project description related to SSM limits in the permit and permit analysis.
Condition II.A.1, Page 23	Please add LPB-2 to condition D.4 on page 23.	Corrected as requested
Condition II.A.1, Page 31	As requested in the BACT Report section 2.2.1, the renewable fuel storage tanks can store either renewable kerosene/SAF or renewable diesel as the PTE is based on renewable kerosene which has the highest VP. MRL tracks	Corrected to allow renewable kerosene/SAF or an equivalent or lower vapor pressure.

	throughput and product on each tank monthly already	
Condition II.A.1, Page 33	Please correct the unit ID from H-4201 to H-4102.	Corrected as requested.
Condition II.A.1, Page 36 and 40	Please remove references to 40 CFR 60, Subpart Dc from the MRL permit (show up on page 36 & 40 MAQP analysis, Section II.C.8.b and Section II.H.d) because: 1. the small LP boilers are too small (< 10 MMBtu/hr) and the facility does not have any other boilers subject to this rule; 2. the process heaters are not steam generating units; 3. the new CoGen turbine is subject to NSPS Subpart KKKK.	DEQ has reviewed the history of Subpart Dc in the context of the permit and determined that reference was included at the request of MRL in a previous comment associated with MAQP #5263-01 thus DEQ has opted to leave the reference for now. Subpart Dc appears to be related to H-4201.
Condition II.A.1, Page 214	Update the PTE table based on the revised summary submitted along with the BACT report, reflecting minor changes to emission calculations and also the SCR control efficiency of the Cogen and the 40MM hydrogen plant	The revised PTE table was inserted into the Emission Inventory Section and into the Air Quality resource section of the EA.
Condition II.A.1, Page 216	A complete GHG impact assessment requires a full life cycle analysis because atmospheric greenhouse gas (GHG) concentrations are indifferent to the source location or scope classification of emissions; consequently, ignoring upstream and downstream emissions (i.e., scope 2 and scope 3 GHG emissions) results in an incomplete evaluation of the climate impacts or benefits of a proposed project [1, 2]. This comprehensive approach is particularly important when evaluating renewable transportation fuels. Renewable fuels, which may produce higher direct	Per DEQ's current standard practice, only Scope 1 emissions are included in the GHG assessment resources area of the Environmental Assessment. These limit the scope of the analysis to direct release of GHG emissions that occur on the site. DEQ will be releasing GHG guidance at the beginning of 2026 will further solidify a more consistent and transparent approach across DEQ projects relating to release of GHGs.

	emissions during fuel refining, generally have a lower life cycle GHG emission impact compared to fossil fuels. The lower life cycle GHG emissions impact result from using renewable feedstocks and energy inputs to produce the fuels, and is recognized by numerous regulatory agencies including EPA Renewable Fuel Standards and California Air Resources Board's (CARB) Low Carbon Fuel Standard [3].	
Condition II.A.1, Page 220	It is important to recognize the limitations of using a global climate model like MAGICC for specific, smaller-scale emissions assessments. MAGICC is a global climate model, and published research [1] reviewing comparison of different power plant projects has noted a key limitation of the model is it is "unable to capture small changes in emissions associated with the construction of a single power plant". Therefore, while MAGICC is valuable for large-scale global technology deployment scenarios and validating general climate metrics, it may not be the most suitable tool for modeling detailed impacts of small-scale project changes due to its global scope and precision limitations. MDEQ in the Preliminary Determination comments highlighted there are "concerns" with the MAGICC model being used to "predict the impacts of very small CO2e contributions from Projects".	Per DEQ's current position, the MAGICC's model will be limited to larger comparisons such as to the largest sectors of Montana's economy and up to and including a comparison to the statewide inventory. DEQ does not believe the model accurately predicts the smallest GHG increases and expects future revisions to the model may better define the smallest increases that should be evaluated using the model directly. See response directly above related to future GHG guidance release.

Public Comments Received from Two (2) commenters

Comments received in comment referenced 5263-03_12_01_PUB_COM2

DEQ has identified within the body of the comment letter, the response reference number that has been assigned for DEQ's response.

To Whom It May Concern:

I am submitting my public comments on December 1, 2025, which is the deadline date for all public comments to be submitted.

The Montana Department of Environmental Quality (MDEQ) should deny the Air Quality Permit (AQP) for Montana Renewables' SAF Expansion to 27,000 barrels of SAF/year based on six main criteria:

1. Airborne pollutants (criteria pollutants and hazardous air pollutants) in the current Phase 1 already come close to exceeding EPA Prevention of Significant Deterioration (PSD), and Phase 2 expansion will increase these pollutants; the combined total surpass PSD Major Modification Significance Levels; (DEQ has identified this as Summary Bullet #1).
2. The AQP application contains data which is in conflict with the DOE EA-2275 FoNSI findings for Montana Renewables' project; (DEQ has identified this as Summary Bullet #2).
3. The AQP application contains data which is in conflict with EPA PSD Major Modification Significance Level standards; (DEQ has identified this as Summary Bullet #3).
4. Exceeding PSD levels triggers the requirement for a PSD permit in compliance with NAAQS and EPA guidelines; (DEQ has identified this as Summary Bullet #4).
5. Affected areas lack proper air monitoring stations to ensure NAAQS, MAAQS and EPA compliance to protect human health and the environment; (DEQ has identified this as Summary Bullet #5).
6. MDEQ should deny the AQP request to remove the Consent Decree (CD) (CD) (CIV-no 01-142LH) conditions and plantwide umbrella limits that were originally specific to the Calumet Montana Refining-Petroleum Refinery. (DEQ has identified this as Summary Bullet #6).
7. A continuous plume of airborne pollutants from Montana Renewables' biofuels processing is blanketing neighborhoods throughout Great Falls; this represents a "taking" that impacts the value of homes and businesses in areas adversely impacted by these airborne emissions; thus, better control technology equipment and solutions are needed to reduce the adverse impacts of these pollutants, as well as an impacts analysis to be performed. (DEQ has identified this as Summary Bullet #7).

EPA's Prevention of Significant Deterioration (PSD) Major Modification Significance Levels

For the above reasons, Montana Renewables' AQP should be denied by the Montana Department of Environmental Quality (MDEQ) on the basis that Phase 1 criteria pollutants and hazardous air pollutants already come close to exceeding the EPA's PSD levels, and combined with Phase 2 levels, the total will exceed PSD Major Modification Significance Levels for the proposed Phase 2 expansion. DEQ has identified this section as Public Comment #1.

Montana Renewables' proposed SAF expansion will produce even more significant increases in criteria pollutants and hazardous air pollutant (HAP) emissions, as compared and contrasted in this AQP and the U.S. Department of Energy's Environmental Assessment 2275 Finding of No Significant Impact (DOE EA-2275 FoNSI), based on pollutant data and analysis contained within both documents and provided by the same engineering consulting firm, Ramboll. DEQ has identified this section above as Public Comment #2.

PSD findings in the DOE EA-2275 FoNSI vs. the AQP

Excerpted from the DOE EA-2275 FoNSI, page 21:

Table 3-1b. Renewables Facility Operation, Estimated Actual Emissions, and Prevention of Significant Deterioration in Major Modification Significance Levels, Source: Ramboll 2024a Preliminary Emissions Estimates in Support of Max SAF Operation. Confidentially prepared for Montana Renewables LLC. March 19

Table 3-1b, footnote (a) states that, "Significance levels (i.e., significant emissions increases) are the net incremental increases in emissions from proposed major air emissions sources or proposed major modifications to existing air emissions sources that are defined as "significant" under PSD regulations at 40 CFR 52.21(b)(23) and at which PSD permitting program requirements are triggered."

Table 3-1b includes Montana Renewables' Phase 1 and Phase 2 emissions, expressed in Quantity (tons per year), and Estimated Actual Emissions (Total) which demonstrates these air emissions now exceed – and will continue to exceed – the triggering threshold for PSD permitting.

In comparison, AQP figures expressing the quantity of emissions are (amazingly) well below the PSD triggering threshold. How can the same engineering consultants arrive at two starkly different conclusions for air emissions in less than a year? How can measuring methods used by the same engineering consultants change emissions results dramatically from one document to another in less than one year?
Which document's findings are accurate, and which document requires substantiation to answer lingering questions? DEQ has identified this section above as Public Comment #3.

PSD Permit Requirements

Exceeding the Prevention of Significant Deterioration Major Modification Significance Level triggers the need for a PSD permit, which requires the installation of Best Available Control Technology (BACT), an air quality analysis, and an additional impacts analysis to ensure compliance with National Ambient Air Quality Standards (NAAQS) as described on the EPA's website as follows:

"Prevention of Significant Deterioration (PSD) (https://www.epa.gov/nsr/prevention-significant-deterioration-basic-information [epa.gov]) applies to new major sources [iaspub.epa.gov] or major modifications [iaspub.epa.gov] at existing sources for pollutants where the area the source is located is in attainment or unclassifiable with the National Ambient Air Quality Standards (NAAQS) [epa.gov]. It requires the following:

1. installation of the "Best Available Control Technology" (BACT);
2. an air quality analysis;
3. an additional impacts analysis; and
4. public involvement [epa.gov]."

Findings from the Air Quality Permit (AQP)

Within this AQP, Montana Renewables' proposed operations fail to utilize best available control technology for most proposed new operations and equipment, and in many cases, allows for the use of the cheapest technology or operating solution available to be implemented. This is unacceptable, and a valid reason for MDEQ to deny this AQP.DEQ has identified this section above as Public Comment #4.

As written, this AQP will lead to significant increases in criteria pollutants and hazardous air pollutants which will increase major adverse health impacts and cancer burdens for neighborhoods surrounding Montana Renewables' refinery operations. Montana Renewables' emissions are in addition to criteria pollutants and hazardous air pollutants currently being emitted from Calumet's co-located fossil fuel operations.

Page 189 of this Air Quality Permit states that, ***"Projected increases in MAQP #5263-03 are large enough to make the facility subject to a review against PSD significant emission rates on future permitting actions."***

These projected increases, as illustrated below, support the need for a PSD permit to be required, along with implementation of Best Available Control Technology, further air quality analysis, additional impacts analysis and public participation, as laid out by the EPA on their website found here: https://www.epa.gov/nsr/prevention-significant-deterioration-basic-information [epa.gov].
DEQ has identified this section above as Public Comment #5.

The AQP states, ***"The MaxSAF modification increases the facility-wide PTE above modeling thresholds listed in Montana's Draft Modeling Guideline for $PM_{2.5}$, NO_2, CO, and VOC and therefore warrants further analyses.*** *As outlined in Sections 4.3 and 4.4.1 of the Modeling Guideline, a screening level significant impact analysis is often an adequate demonstration of compliance if the project-only emission increases do not exceed significant impact levels (SIL) for the applicable pollutant. Project-only emission increases were first modeled to determine if any model receptors exceeded the Class II SILs, presented in* ***Table VI-1****, and* ***no receptors exceeded the SIL****."*

Comparing and contrasting Ramboll's data and analysis in the AQP versus the DOE EA-2275 FoNSI

The first statement, ***"The MaxSAF modification increases the facility-wide PTE above modeling thresholds listed in Montana's Draft Modeling Guideline for $PM_{2.5}$, NO_2, CO, and VOC and therefore warrants further analyses,"*** confirms Ramboll's conclusions as found in the DOE EA-2275 FoNSI, in Table 3-1b.

Table 3-1b shows Phase 1, Phase II and Total Estimated Actual Emissions for Particulate Matter (PM_{10} and $PM_{2.5}$), Nitrogen Oxide (NO_2), Carbon Monoxide and Volatile Organic Compounds (VOCs) all exceeding PSD Major Modification Significance Levels (PSD level).

The last statement, ***"no receptors exceeded the SIL"*** explicitly contradicts air emissions source data provided by Ramboll for the DOE EA-2275 FoNSI in Table 3-1b.
DEQ has identified this section above as Public Comment #6.

EPA's PSD Thresholds for Major Sources and for Modifications to Major Sources

The EPA's major source threshold for criteria pollutants is 100 tons per year. For hazardous air pollutants, the threshold is 10 tons per year for a single pollutant, or 25 tons per year for any combination of pollutants as sourced from the EPA's website: https://www.epa.gov/title-v-operating-permits/who-has-obtain-title-v-permit [epa.gov].

However, for the EPA's Major Modification Significance Levels, these PSD levels change as follows:

Major Source For SO2, the level is 40 tons per year.
For NO2, the level is 40 tons per year.
For CO, the level is 100 tons per year.
For PM, the level is 25 tons per year. For
PM10, the level is 15 tons per year. For
PM 2.5, the level is 10 tons per year.

For VOC's, the level is 40 tons per year.

EPA Title V Requirements

According to the EPA's website, noted above, any major source that exceeds the 100 tons per year threshold must obtain a Title V Permit. This is in addition to a PSD permit. As excerpted from the EPA's website:

Who Has to Obtain a Title V Permit? Any major source:

- A major source has actual or potential emissions at or above the major source threshold for any "air pollutant."
- The major source threshold for any air pollutant is 100 tons/year (this is the "default value").
- Lower thresholds apply in non-attainment areas (but only for the pollutant that are in non-attainment). (See Table 1 below).
- Major source thresholds for "hazardous air pollutants" (HAP) are 10 tons/year for a single HAP or 25 tons/year for any combination of HAP.
- The EPA generally has not required non-major sources to get permits (except as shown below).any major point-source of air emissions that

Page 40 of the AQP explains the rationale for excluding Montana Renewables from a Title 5 Permit requirement.
DEQ has identified this section above as Public Comment #7.

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

Title 5 Permit requirements should apply to both Montana Renewables and Calumet, even though ownership has been legally changed. Montana Renewables and Calumet are co-located and operating from the same land mass area, each producing criteria pollutants and hazardous air pollutants that, when combined, most likely exceed every possible established threshold level for these pollutants, all of which are being emitted around the clock from this same location, 24 hours a day, seven days a week, 365 days a year, except during operational shutdowns for repairs, etc., and blanketing entire neighborhoods surrounding their joint operations.

Legal separation of these entities, operating at the same location and jointly creating massive increases in air emissions – that, without Best Available Control Technology requirements, will continue unabated – should not be allowed to determine Title V Permit requirements.
DEQ has identified this section above as Public Comment #8.

"Additionally, the application requests changes that are administrative in nature and are unrelated to the MaxSAF™ project. Specifically, MRL requested removal of Consent Decree (CD) (CIV-no 01-142LH) conditions and plantwide umbrella limits that were originally specific to the Calumet Montana Refining-Petroleum Refinery. It has since been determined that although the Calumet Montana Refining-Petroleum Refinery is considered the same source as MRL for Title V Purposes, for Prevention of Significant Deterioration (PSD) purposes, they are considered separate sources; therefore, the limits should be administratively removed from the MRL MAQP and thereafter, also from the MRL Title V Operating Permit."

MDEQ should deny the AQP request for removal of this Consent Decree.
DEQ has identified this section above as Public Comment #9.

As found in the DOE-EA2275 FoNSI and this AQP, Montana Renewables' Max SAF operations will exceed applicable PSD thresholds, thus qualify as a major source of pollution that requires Title V permitting and triggers a PSD Permit, as well as the implementation of Best Available Control Technology.

Montana's PSD Thresholds for Major Sources and for Modifications to Major Sources

Montana's Prevention of Significant Deterioration (PSD) levels for criteria pollutants are based on the potential to exceed thresholds of 100 tons per year for major sources like sulfur dioxide, nitrogen oxides and particulate matter.

For SO2, the level is 100 tons per year. For
NO2, the level is 100 tons per year.
For CO, the level is 100 tons per year. Carbon Monoxide is an HAP. For
PM, the level is 100 tons per year.
For PM10, the level is 100 tons per year.
For PM 2.5, the level is 100 tons per year.
For VOC's, the level is 100 tons per year. VOC's are HAPs.

However, for major modifications, Montana's PSD threshold levels change. Montana's Prevention of Significant Deterioration program requires that any source with a potential to emit more than 10 tons per year of any individual hazardous air pollutant (HAP) or more than 25 tons per year of combined HAPs must obtain a Title V operating permit.

Thus, Carbon Monoxide and VOCs, combined, exceed Montana's PSD threshold, as illustrated in the DOE EA-2275 FoNSI, with data originating from Ramboll.
DEQ has identified this section above as Public Comment #10.

Comparing and Contrasting Emissions as found in the DOE EA-2275 FoNSI and the AQP

1. Nitrogen Oxide

In Table 3-1b, Phase 1 emissions for Nitrogen Oxide (NOx), categorized by the EPA as a criteria pollutant, indicates 89.37 tons per year. Phase 2 emissions indicate an increase of 153.41 tons per year. Total: 242.78 tpy.

The Major Modifications Significance Level is 40 tons per year. Thus, the total NOx emissions increase of 153.41 tpy exceeds this threshold by 3.83525x (153.41 divided by 40), warranting a PSD Permit.

In the AQP, however, on page 189, NOx emissions for the existing facility (which correlates to Phase 1 in the DOE EA-2275 FoNSI) is shown at 89.53 tons per year (tpy), Project Increase (which correlates to Phase 2 in the FoNSI) is shown at 93.13 tpy, and the "Updated Facility Wide Total" (which corresponds to the Estimated Actual Emissions Total in the FoNSI) is 182.66 tpy.

The PSD Major Threshold level is shown as 100 tons per year – which, while true, is not applicable. Instead, the PSD Major Modification Significance Level for NOx was required to be used, and this threshold is not 100 tons per year. It is 40 tons per year – which means the increase exceeds the PSD threshold by 2.32825x (93.13 divided by 40).

Thus, Ramboll's conclusion, that the "Project Trigger PSD" is NO," cannot be true, based on the increase in emissions which exceed the PSD threshold for Major Modifications. The correct answer is YES; the NOx emissions trigger a PSD Permit. DEQ has identified this section above as Public Comment #11.

2. Volatile Organic Compounds (VOCs)

In Table 3-1b, Phase 1 emissions for VOCs, categorized by the EPA as hazardous air pollutants (HAPs), indicates 94.96 tons per year. Phase 2 indicates an increase of 58.22 tpy. Total is 153.18 typ. The increase of 58.22 tpy exceeds the PSD Major Modification Significance level of 40 tons per year by 1.4555x, warranting a PSD Permit.

In the AQP, however, on page 189, VOCs emissions for the existing facility (which correlates to Phase 1 in the DOE EA-2275 FoNSI) is shown at 64.47 tons per year (tpy), Project Increase (which correlates to Phase 2 in the FoNSI) is shown at 81.53 tpy, and the "Updated Facility Wide Total" (which corresponds to the Estimated Actual Emissions Total in the FoNSI) is 146.00 tpy.

The PSD Major Threshold level is shown as 100 tons per year – which, while true, is not applicable. Instead, the PSD Major Modification Significance Level for VOCs was required to be used, and this threshold is not 100 tons per year. It is 40 tons per year – which means the increase exceeds the PSD threshold by 2.03825x (81.53 divided by 40).

Thus, Ramboll's conclusion, that the "Project Trigger PSD" is NO," cannot be true, based on the increase in emissions which exceed the PSD threshold for Major Modifications. The correct answer is YES; VOCs emissions trigger a PSD Permit. DEQ has identified this section above as Public Comment #12.

3. Particulate Matter (PM10 and PM2.5 are designated by the EPA as criteria pollutants)

A. PM10

In Table 3-1b, Phase 1 emissions for PM10, categorized by the EPA as a criteria pollutant, indicates 9.06 tons per year. Phase 2 emissions indicate an increase of 25.02 tons per year. Total: 34.08 tpy.

The Major Modifications Significance Level is 15 tons per year. Thus, the total PM10 emissions increase of 25.02 tpy exceeds this threshold by 1.668x (25.02 divided by 15), warranting a PSD Permit.

In the AQP, however, on page 189, PM10 emissions for the existing facility (which correlates to Phase 1 in the DOE EA-2275 FoNSI) is shown at 9.07 tons per year (tpy), Project Increase (which correlates to Phase 2 in the FoNSI) is shown at 28.20 tpy, and the "Updated Facility Wide Total" (which corresponds to the Estimated Actual Emissions Total in the FoNSI) is 37.27 tpy.

The PSD Major Threshold level is shown as 100 tons per year – which, while true, is not applicable. Instead, the PSD Major Modification Significance Level for PM10 was required to be used, and this threshold is not 100 tons per year. It is 15 tons per year – which means the increase exceeds the PSD threshold by 1.868x (28.02 divided by 15).

Thus, Ramboll's conclusion, that the "Project Trigger PSD" is NO," cannot be true, based on the increase in emissions which exceed the PSD threshold for Major Modifications. The correct answer is YES; PM10 emissions trigger a PSD Permit. DEQ has identified this section above as Public Comment #13.

B. PM2.5

In Table 3-1b, Phase 1 emissions for PM2.5, categorized by the EPA as a criteria pollutant, indicates 8.87

tons per year. Phase 2 emissions indicate an increase of 25.02 tons per year. Total: 33.89 tpy.

The Major Modifications Significance Level is 10 tons per year. Thus, the total PM2.5 emissions increase of 25.02 tpy exceeds this threshold by 2.502x (25.02 divided by 10), warranting a PSD Permit.

In the AQP, however, on page 189, PM2.5 emissions for the existing facility (which correlates to Phase 1 in the DOE EA-2275 FoNSI) is shown at 8.89 tons per year (tpy), Project Increase (which correlates to Phase 2 in the FoNSI) is shown at 28.20 tpy, and the "Updated Facility Wide Total" (which corresponds to the Estimated Actual Emissions Total in the FoNSI) is 37.09 tpy.

The PSD Major Threshold level is shown as 100 tons per year – which, while true, is not applicable. Instead, the PSD Major Modification Significance Level for PM10 was required to be used, and this threshold is not 100 tons per year. It is 10 tons per year – which means the increase exceeds the PSD threshold by 2.82x (28.02 divided by 10).

Thus, Ramboll's conclusion, that the "Project Trigger PSD" is NO," cannot be true, based on the increase in emissions which exceed the PSD threshold for Major Modifications. The correct answer is YES; PM2.5 emissions trigger a PSD Permit. DEQ has identified this section above as Public Comment #14.

4. Carbon Monoxide (CO)

In Table 3-1b, Phase 1 emissions for CO, categorized by the EPA as a hazardous air pollutant, indicates 78.10 tons per year. Phase 2 emissions indicate an increase of 123.16 tons per year. Total: 201.26 tpy.

The Major Modifications Significance Level is 100 tons per year. Thus, the total CO emissions increase of 123.16 tpy exceeds this threshold by 1.2316x (123.16 divided by 100), warranting a PSD Permit.

In the AQP, however, on page 189, CO emissions for the existing facility (which correlates to Phase 1 in the DOE EA-2275 FoNSI) is shown at 78.24 tons per year (tpy), Project Increase (which correlates to Phase 2 in the FoNSI) is shown at 91.39 tpy, and the "Updated Facility Wide Total" (which corresponds to the Estimated Actual Emissions Total in the FoNSI) is 169.63 tpy.

The PSD Major Threshold level is shown as 100 tons per year – which, while true, is not applicable because this applies only to existing sources.

Instead, PSD Major Modification Significance Level for CO was required to be used, and this threshold is also 100 tons per year. While this increase of 91.39 tpy is less than 100 tpy, given that other mistakes have been made in this AQP table on page 189, the MDEQ should verify this increase is accurate and valid. Clearly, it is significantly less – 31.77 tons per year –than the increase shown in the DOE EA-2275 FoNSI, and given that most of the other figures in this AQP table are close to the figures in the FoNSI, it begs the question of how CO was measured and calculated in the AQP to avoid triggering a PSD Permit. How could CO emissions be 31.77 tons per year greater in the FoNSI than in the AQP? DEQ has identified this section above as Public Comment #15.

Thus, Ramboll's conclusion, that the "Project Trigger PSD" is NO," is true if the increase in CO emissions proves to be a valid number in the AQP, and the increase in CO emissions proves to be an invalid number in the DOE EA-2275 FoNSI. Given that Ramboll is the source for both sets of data in these documents, it begs the question of which figures are correct and true, and which figures are incorrect and false. The correct answer to the "Project Trigger PSD" question is MAYBE – CO emissions MAY trigger a PSD Permit, but require MDEQ's verification. DEQ has identified this section above as Public Comment #16.

As a reminder, a DOE $1.67 billion dollar taxpayer-funded loan was based on the emissions data found in Table 3-1b, as well as other information within the DOE EA-2275 FoNSI. If the Table 3-1b data proves to be incorrect and false, then the DOE LPO team should be notified that there are corrections need to be made to the FoNSI, and these findings may warrant a full review of emissions data to determine if, in fact, these findings are determined to be significant. DEQ has identified this section above as Public Comment #17.

Likewise, it should also be noted that within the FoNSI Table 3-1b, another calculation reflects a serious misstatement of facts. The **Total Combined Hazardous Air Pollutants (HAPs)** in Phase 1 is shown as 8.19 tons per year. The Phase 2 increase in HAPs is shown as 5.84 tons per year. The total is shown as 14.03 tons per year.

It appears that all three figures are false: Phase 1, Phase 2 and the "total" numbers. DEQ has identified this section above as Public Comment #18.

According to the EPA, hazardous air pollutants include emissions from Carbon Monoxide (CO) and Volatile Organic Compounds (VOCs).

As a reminder, Table 3-1b Phase 1 CO emissions are shown as 78.10 tpy, Phase 2 CO emissions are shown as 123.16, and the total CO emissions are 201.26 tpy. Phase 1 VOCs are shown as 94.96 tpy, Phase 2 VOCs are shown as 58.22 tpy, and the total VOCs are 153.18 tpy.

Combined CO and VOC emissions for Phase 1 total 173.06 tpy – this figure exceeds the Phase 1 HAP total figure of 8.19 tpy by 164.87 tons per year.

Combined CO and VOC emissions for Phase 2 total 181.38 tpy – this figure exceeds the Phase 2 HAP figure by 175.54 tons per year.

Thus, within Table 3-1b, combined CO and VOC emissions for the Estimated Actual Emissions Total equal 354.44 tpy (201.26 + 153.18) – this figure exceeds the Total HAP figure of 14.03 tpy by 340.41 tons per year.

If this proves true, this is not an insignificant finding. DEQ has identified this section above as Public Comment #19.

EPA Limits for Nitrogen Oxide and VOCs

Phase 2 emissions for Nitrogen Oxide and Volatile Organic Compounds both exceed their respective their PSD Major Modification Significance Levels, and these increases qualify this project as a MAJOR source. Combined, NOx and VOCs contribute to Ozone (O3), which qualifies this project as a MAJOR source for Ozone, as well, as defined by the EPA below.

On Page 19 of the DOE EA-2275 FoNSI, Ozone (O3) was dismissed as a relevant. Based on NOx and VOCs emissions which are shown in the DOE EA-2275, this appears to be a false conclusion based on the following:

"Per the MDEQ Air Quality Bureau's 2023 Annual Monitoring Network Plan, an evaluation of EPA monitoring site setup criteria, historical monitoring data, and meteorological patterns, in combination with MDEQ's professional judgment, determined that ambient air monitoring in the Great Falls Metropolitan Statistical Area was warranted for only PM2.5 (MDEQ 2023). The 24-hour average NAAQS for PM2.5 is 35 micrograms per cubic meter (µg/m3); the annual average NAAQS is 9.0 µg/m3."

Within the AQP, Ozone was again dismissed as relevant based on the following conclusions, which contradict the emissions increases as shown in the AQP on Page 199:

*"**Table VI-10** lists all 3 of the modeled PM2.5 NAAQS violations and identifies the relative contribution of the MaxSAF project and MRL (inclusive of MaxSAF) at the time and location of each exceedance. In accordance with EPA's Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program, SILs may be used in a cumulative modeling demonstration to identify whether the applicant facility is "culpable" in the event of a modeled NAAQS violation. As discussed in the 2024 Supplement to the Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program (EPA), because the PM2.5 SIL values are set based on the range of intrinsic variability in ambient air observations, modeled impacts that are less than the SIL (even in a cumulative NAAQS analysis) are considered statistically insignificant. **Therefore, in similar fashion to the use of SILs in a screening-level capacity, if the modeled impacts from the applicant facility is less than that of the applicable SIL at the violating receptor location (and time, for short term averaging periods), then it has been demonstrated that the facility will not cause or contribute to a violation of the NAAQS.**"*

While this last statement may be true, in and of itself, it is carefully worded and it does not appear to apply to Montana Renewables' Max SAF project, directly or indirectly, based on the NOx and VOCs emissions increases over the PSD Major Modification Significance Levels as stated in the AQP. The conclusion that Ozone and Fine Particles (PM10 and PM2.5) do not contribute to or violate National Ambient Air Quality Standards (NAAQS) appears to be false.
DEQ has identified this section above as Public Comment #20.

The EPA's website states the following, with applications to Montana Renewables Max SAF project highlighted in bold text:

§ 52.21 Prevention of significant deterioration of air quality.

A major source that is major for volatile organic compounds or NO_x shall be considered major for ozone.

*(2) **Applicability procedures.***

*(i) The requirements of this section apply to the construction of any new major stationary source (as defined in paragraph (b)(1) [ecfr.gov] of this section) or **any project at an existing major stationary source in an area designated as attainment or unclassifiable u**nder sections 107(d)(1)(A)(ii) or (iii) of the Act.*

> *(ii) The requirements of paragraphs (j) [ecfr.gov] through (r) [ecfr.gov] of this section apply to the construction of any new major stationary source **or the major modification of any existing major stationary source,** except as this section otherwise provides.*
>
> *(iii) **No new major stationary source or major modification to which the requirements of paragraphs (j) [ecfr.gov] through (r)(5) [ecfr.gov] of this section apply shall begin actual construction without a permit that states that the major stationary source or major modification will meet those requirements.** The Administrator has authority to issue any such permit.*

Source: eCFR.gov [ecfr.gov], Title 40, Chapter 1, Subchapter C, Part 52, Subpart A, https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-52/subpart-A/section-52.21 [ecfr.gov]

Thus, Montana Renewables' Max SAF project emissions of NOx, VOCs and O3 emissions violate the NAAQS, and this project requires a Title V permit and a PSD permit, and use of Best Available Control Technology, an air quality analysis, an additional impacts analysis and public participation as stated in the EPA's website noted above.
DEQ has identified this section above as Public Comment #21.

Air Quality Permit Hazardous Air Pollutants as shown in the Emissions Inventory Table on Page 189.

Within the AQP, Total HAPs for the Existing Facility are shown as 6.53 (tpy). This table does not indicate units of measure, but it seems prudent to assume that tons per year are the applicable units.

Total HAPs for the Project Increase are shown as 10.25 (tpy).

Total HAPs for Updated Facility Wide Total are shown as 16.78 (tpy).

This is important because, according to the EPA, CO and VOCs are hazardous air pollutants.

For the Existing Facilities, CO and VOC emissions combined equal 142.71 tpy (78.24 + 64.47), which exceeds the figure of 6.53 tpy by 136.18 tpy.

For the Project Increases, CO and VOC emissions combined equal 172.92 tpy (91.39 + 81.53), which exceeds the figure of 10.25 tpy by 162.67 tpy.

Lastly, for the Updated Facility Wide Total, CO and VOC emissions combined equal 315.63 tpy, which exceeds the figure of 16.78 tpy by 298.85 tpy.

It's not clear where the page 189 Emissions Inventory Table figures for Total HAPs was derived, or calculated. This is a request for clarification of these figures.
DEQ has identified this section above as Public Comment #22.

The AQP states that, *"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."*

However, this AQP does not list HAPs, nor does it state that the EPA designates Carbon Monoxide and VOCs as Hazardous Air Pollutants.
DEQ has identified this section above as Public Comment #23.

N-Hexane

Lastly, below Table 3-1b in the DOE EA-2275, footnote "b" states, "*N-hexane was identified as the largest single HAP in the preliminary engineering design emission estimates. Actual emissions would be calculated later as appropriate to the permit application."*

Nowhere, in the AQP, is n-hexane mentioned one time. **MDEQ, please clarify why N-hexane has been omitted from your consideration as an HAP within this AQP.**
DEQ has identified this section above as Public Comment #24.

The EPA's website states that *"Major source thresholds for "hazardous air pollutants" (HAP) are 10 tons/year for a single HAP or 25 tons/year for any combination of HAP."*

Therefore, the "largest single HAP" emitted by the Montana Renewables' Max SAF site is N-hexane, and the EPA limit is 10 tons per year. Anything over that limit qualifies the site as a major source. The DOE EA-2275 FoNSI Table 3-1b shows the Phase 1 N-hexane level as 7.83 tpy, the Phase 2 level is 5.49 tpy, and the Estimated Actual Emissions Total of N-hexane is 13.32 tpy. Clearly, this volume surpasses the EPA's 10 tons per year limit, which means a Title V Permit is required.
DEQ has identified this section above as Public Comment #25.

Summary: Comparing and Contrasting Emissions Data Found in the AQP and the DOE EA-2275 FoNSI

Not only does it appear that errors were made in this AQP with regard to the emissions data, on which analysis and conclusions were based, what appears to be errors in the AQP have also led to the discovery of what could be serious errors with regard to the emissions data in Table 3-1b within the DOE EA-2275 FoNSI, as well.

The AQP and DOE EA-2275 FoNSI documents appear to contain significant errors regarding increases in emissions for NOx, PM10, PM2.5 and potentially CO, which would point to triggers for a PSD Permit, Title V permit and potentially a full review of the DOE EA-2275 FoNSI to determine if these findings are, in fact, significant.

The EPA's website states that *"Major source thresholds for "hazardous air pollutants" (HAP) are 10 tons/year for a single HAP or 25 tons/year for any combination of HAP,"* this seems to indicate that

Montana Renewables' Max SAF project emissions for HAPs would trigger a requirement for a Title V Permit, a PSD Permit, and the additional EPA requirements listed earlier. Source: https://www.epa.gov/title-v-operating-permits/who-has-obtain-title-v-permit [epa.gov]

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Based on starkly contradictory emissions estimates and analysis for Montana Renewables' Max SAF expansion project as shown on the AQP and the DO EA-2275 FoNSI, MDEQ must deny this Air Quality Permit on the basis that a *"PSD permit is required, which includes the installation of the Best Available Control Technology (BACT), an air quality analysis, and an additional impacts analysis. This process ensures that any increase in emissions does not violate National Ambient Air Quality Standards (NAAQS) and protects public health and the environment,"* according to the EPA. Additionally, MDEQ must deny this AQP on the basis that the ai emissions data trigger the requirement for a Title V Permit also.
DEQ has identified this section above as Public Comment #26.

MDEQ – Request for Clarification

The Air Quality Permit states, "*However, the Modeling Guideline clarifies that DEQ may request that all sources of emissions be modeled in cases where facility-wide modeling has not previously been conducted and approved. Due to a lack of representative modeling in the area surrounding MRL as well as a lack of previous MRL facility-wide modeling, DEQ deemed it inappropriate to conclude that the project emissions and existing facility emissions would not cumulatively cause or contribute to a violation of any NAAQS or MAAQS.* ***Thus, DEQ requested that a full impact analysis inclusive of nearby sources and background concentrations be performed for*** $PM_{2.5}$ ***and*** NO_2***, as informed by preliminary results provided by MRL and Ramboll.****"*

Why did the MDEQ require further analysis for PM2.5 and NOx, and not for PM10? Why did MDEQ not require further analysis for hazardous air pollutants of Carbon Monoxide and VOCs? Please provide clarification.
DEQ has identified this item as Public Comment #27.

Vastly different measurements/data for criteria pollutants (PM_{10}, $PM_{2.5,}$ and NO_2), and hazardous air pollutants (CO and VOCs) in the MDEQ Air Quality Permit and the DOE EA-2275 FoNSI, which means something is amiss, and a full PSD permit, an air quality analysis, an additional impacts analysis, and public participation are required to assess the true volume of air emissions from the proposed SAF facility expansion. MDEQ should review the findings within this set of public comments for the AQP, and clarify if emissions data have been correctly presented, and whether they are accurate, or not
DEQ has identified this section above as Public Comment #28.

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DOE $1.67 Billion Dollar Loan and No Air Quality Monitoring Stations located in Great Falls

In January 2025, Montana Renewables was awarded a $1.67 billion dollar loan from the DOE to scale up their facilities to develop a substantial increase in the volume of sustainable aviation fuels produced. In light of this fact – that Montana Renewables is sitting on a mountain of taxpayer funded cash – there is no valid justification, or excuse, for Montana Renewables not to implement the Best Available Control Technology that currently exists, and to rein in and control their criteria pollutants and hazardous air pollutants being emitted in a continuous overhead plume from their refinery's around-the-clock operations.
DEQ has identified this section above as Public Comment #29.

The DOE EA-2275 FoNSI provides highly relevant factual information especially with regard to Air Quality Monitoring Stations, or the lack thereof. Source: https://www.energy.gov/sites/default/files/2025-01/final-fonsi-ea-2276-renewable-fuels-biomass-energy-facility-conv-2024-12.pdf [energy.gov].

"MRL is co-located with CMR, a traditional crude oil refinery in Great Falls, Cascade County, Montana. This area is designated as an attainment area for all criteria pollutants, meaning the area achieves the NAAQS. To determine NAAQS attainment status, federal regulations require each state to establish an ambient air monitoring network (refer to 40 CFR Part 58, Appendix D) to measure pollutant concentrations. Per the MDEQ Air Quality Bureau's 2023 Annual Monitoring Network Plan, an evaluation of EPA monitoring site setup criteria, historical monitoring data, and meteorological patterns, in combination with MDEQ's professional judgment, determined that ambient air monitoring in the Great Falls Metropolitan Statistical Area was warranted for only PM2.5 (MDEQ 2023). The 24-hour average NAAQS for PM2.5 is 35 micrograms per cubic meter (µg/m3); the annual average NAAQS is 9.0 µg/m3. ***The sole Great Falls air quality monitoring station is within 2 miles of the Project site. The next-closest multi-pollutant monitoring station is the National Core Monitoring Site (NCore), located in a wilderness area north of Helena, Montana.*** *Per the 2023 Annual Monitoring Network Plan, the average monitored PM2.5 concentration in calendar year 2022 was 5.3 µg/m3* ***at the Great Falls station. However, data from this monitoring station are for informational purposes; the station is not certified to present data for comparison to the 24-hour average NAAQS.*** *The NAAQS design value (a statistic used for relative comparison to the NAAQS) at the NCore station in calendar year 2020–2022 was 30 µg/m3 for the 24-hour average NAAQS and 4.3 µg/m3 for the annual NAAQS, respectively.* ***The NCore monitoring data showed no exceedances of the NAAQS for any pollutant in 2022****."*

Based on this information found in the DOE EA-2275 FoNSI, the public can conclude that neither air quality monitoring station is effectively monitoring any criteria air pollutants or hazardous air pollutants, and neither is accurately measuring the resulting air degradation in Great Falls, Montana.

Within the AQP, there is no mention of the fact that the closest air quality monitoring station in Great Falls is two miles from the refinery and it is not certified, therefore data cannot be used. There is no mention of the fact that NCORE is the next closest station, and it is located in the wilderness outside of Helena.
DEQ has identified this section above as Public Comment #30.

Within the AQP the only mention of Air Quality Monitoring Stations is found here, in this paragraph:

"Background monitors were selected from Montana's Air Quality Monitoring Network Plan (2025), based on the closest and most representative sites with available data. The following PM2.5 and NO2 monitoring sites were identified for use for background concentrations. For PM2.5, the most recent complete dataset (2021-2023) from the Great Falls monitor (AQS ID: 30-013-0001) was used to calculate background design concentration. For NO2, design values were calculated from the Lewistown monitor (AQS ID: 30-027-

0006), as it's the nearest NO2 monitoring site and features a similar airshed to Great Falls. The background concentrations presented in ***Table VI-2*** *were added to the modeled concentrations in the full impact (i.e., cumulative) NAAQS/MAAQS analysis."*

There is simply no valid justification or excuse for the lack of air quality monitoring stations in Great Falls. However, this can be easily fixed.
I believe this is a dereliction of duty on the part of the Montana DEQ, and it represents clear failure to protect the health of people, animals and the environment. It also represents an opportunity now to do the right thing, and install the necessary air quality monitoring stations that will yield actual quantitative and qualitative data going forward.

Stationary air quality monitoring stations are needed to measure and provide quantitative and qualitative data on air emissions that can be independently verified. This data must not be controlled by, and obtained from, point-source pollution generators, as this simply creates a fox-guarding-the-henhouse scenario that ultimately leads to data being distorted by Alice-in-Wonderland logic, and obscured from public review.

Air quality multi-pollutant monitoring stations are not exorbitantly priced outside the MDEQ agency's budget. Kunak Technologies, which was found online during my research, is a leading provider of air quality monitoring systems and solutions, https://kunakair.com [kunakair.com].

Kunak Technologies can address the MDEQ's lack of air quality monitoring stations. Montana Renewables can implement and utilize this company's technology, as well.

Kunak produces a wide range of monitoring systems that can measure pollutants, identify sources of fugitive emissions (leaky vents and pipes that require repairs or replacements), and notify multiple parties (EPA, MDEQ, Montana Renewables, Cascade County Commissioners, City Commissioners and community organizations) via email alerts when criteria pollutants and hazardous air pollutants emissions surpass EPA regulatory standards, and pose a risk to human health and the environment.

The technology has already been invented. It exists. There is no valid reason not to use this, or a comparable technology which produces the same benefits or better.
DEQ has identified this section above as Public Comment #31 and covers all monitoring comments directly above.

Air Quality Monitoring Station and NAAQS Issues as Revealed in the DOE EA-2275 FoNSI and the AQP

There are several problems with the DOE's analysis and conclusions – which contradict and challenge the data and conclusions laid out in this Air Quality Permit. These two documents demonstrate dramatically different and starkly conflicting air emissions results were achieved.

The DOE-EA-2275 FoNSI states that "MRL is co-located with CMR, a traditional crude oil refinery in Great Falls, Cascade County, Montana." However, it also states that, "This area is designated as an attainment area for all criteria pollutants, meaning the area achieves the NAAQS."

It does not appear that there is any information to substantiate that this area around the refinery achieves NAAQS, since there is no actual data.

Request for MDEQ clarification: Please provide clarification which supports the conclusion that, "This area is designated as an attainment area for all criteria pollutants, meaning the area achieves the NAAQS," because if this cannot be provided, it's most likely false.

DEQ has identified this section above as Public Comment #32.

According to this Air Quality Permit on page 189, https://deq.mt.gov/files/Air/AirQuality/Documents/ARMpermits/5263-03_PD.pdf, as of July 8, 2002, Cascade County is designated as an Unclassifiable/Attainment area for all criteria pollutants."

What's striking about this statement is that hazardous air pollutants are not included in this designation.
What about hazardous air pollutants?
DEQ has identified this section above as Public Comment #33.

Criteria pollutants include Sulfur Dioxide (SO2), Nitrogen Dioxides (NO2), Lead (Pb) and Particulate Matter (PM, PM10 and PM2.5), while hazardous air pollutants include Carbon Monoxide (CO) and Volatile Organic Compounds (VOCs) according to the EPA's website for NAAQS standards https://www.epa.gov/criteria-air-pollutants/naaqs-table [epa.gov].

(Note: According to Wikipedia, https://en.wikipedia.org/wiki/NOx [en.wikipedia.org], "in atmospheric chemistry, NO_x is shorthand for nitric oxide and nitrogen dioxide, the nitrogen oxides that are most relevant for air pollution. These gases contribute to the formation of smog and acid rain, as well as affecting tropospheric ozone.")

Montana Renewables' SAF operations began production in 2022. The DOE EA-2275 FoNSI was dated December 16, 2024. Montana Renewables' criteria pollutants and hazardous air pollutants emissions from 2022 to 2024 were neither identified, nor quantified, nor disclosed in this FoNSI. The DOE's conclusion that NAAQS standards were not exceeded cannot be substantiated as factually true.

MDEQ Request for Clarification: Are NAAQS standards being exceeded by this AQP for Montana Renewables? MDEQ, please provide the missing emissions data for 2022 to 2024 as this will reflect SAF operations conducted by Montana Renewables during this timeframe.
DEQ has identified this section above as Public Comment #34.

Likewise, this Air Quality Permit states that,*"MRL demonstrated compliance with all applicable NAAQS and MAAQS, presented in* ***Table VI-1****. Additionally, compliance was shown for the only applicable Class II Increment."*

MDEQ Request for Clarification: Is Montana Renewables in compliance with all applicable NAAQS and MAAQS, and that compliance was shown for the only applicable Class II increment in Table VI-1? Please confirm if these statements are accurate and true.
DEQ has identified this section above as Public Comment #35.

Given the completely contradictory emissions data found in the DOE's EA-2275 FoNSI and this Air Quality Permit, conclusions within both documents are highly questionable. The use of 8-hour and 24-hour increments to measure air emissions can be manipulated by temporary operation shut-downs, especially to change equipment or perform repairs.

These brief 8-hour and 24-hour incremental types of measurements are easily replicated, and resulting emissions increments do not show the cumulative impacts of air pollutants collecting and condensing as a result of around-the-clock operations (24 hours a day, 7 days a week, 365 days per year), or their cumulative concentration levels that collect and blanket local neighborhoods depending on the wind's direction and shifts.

While these methods may be allowed by the EPA, they do not appear to be straightforward, and the results in

this Air Quality Permit do not appear to be truly indicative of actual air emissions for criteria pollutants and hazardous air pollutants.
DEQ has identified this section above as Public Comment #36.

LEAD (Pb) is a Question-mark Issue

Lead (Pb) has been uniformly removed from consideration as a criteria air pollutant in Montana Renewables' Air Quality Permit, even though lab results for the "PTU H2O Rundown Testing" presented measurable quantities of lead in the wastewater sample, in several types of tests. This sample, from Montana Renewables SAF operations, was submitted by Calumet to the lab for analysis, and results can be found in document B23082631 dated September 14, 2023.

MDEQ, please clarify: How can lead appear in measurable quantities in the wastewater from the PTU (pretreatment unit) tank, yet not appear as a criteria pollutant in Montana Renewables' air emissions?
DEQ has identified this section above as Public Comment #37.

Neighborhoods that are subjected to continuous, wind-driven pollutant-laden plumes tend to house people who are often too poor to move to other locations with cleaner air, see doctors on a regular basis, or afford health insurance, or increases in health insurance premiums. As a result, these people – especially elderly, children, babies, pregnant mothers and their unborn babies – tend to suffer far greater negative health impacts caused by this pollution, as well as harms to future generations.

Every Great Falls, Montana neighborhood that sits under a continuous – or intermittently shifting – plume of criteria pollutants and hazardous air pollutants, from any point-source pollution generator, is being adversely affected and harmed. These harms are cumulative, inducing an increase in overall cancer burdens, permanent injuries, and premature deaths for those people who are too poor to move away from these neighborhoods and seek shelter where the air is cleaner.

The fact that "The sole Great Falls air quality monitoring station is within 2 miles of the Project site. The next-closest multi-pollutant monitoring station is the National Core Monitoring Site (NCore), located in a wilderness area north of Helena, Montana" means there are NO certified air quality monitoring stations – none – located in Great Falls.

This Air Quality Permit states that, "As of July 8, 2002, Cascade County is designated as an Unclassifiable/Attainment area for all criteria pollutants."

Clearly, this designation is not based on **actual data** from an air quality multi-pollutant monitoring station located in Great Falls, or anywhere near Great Falls. This designation is for all of Cascade County, which is primarily rural, with the city of Great Falls serving as the only major area of population and industry.

Additionally, this Air Quality Permit makes it clear that there are numerous point-source pollution generators in Great Falls which are contributing their unique signature blends of air emissions that further exacerbate adverse impacts to Montana's overall climate. Clearly, if there are no air quality monitoring stations in Great Falls, then criteria pollutants and hazardous air pollutants are not being measured quantitatively or qualitatively, therefore these emissions are not being regulated, mitigated or properly managed by the MDEQ.

Uncontrolled and unmitigated air pollution plumes reduce people's ability to work full-time due to their own illness and disease, or that of their children and elders under their care. Uncontrolled and unmitigated pollution creates huge economic costs to families, individuals and businesses, and fallout that will show up in an impacts analysis to be performed as part of this PSD permitting process.

In this Air Quality Permit, "MDEQ's professional judgment" appears to have been the most significant deciding factor, combined with historical monitoring data, and meteorological patterns, while actual data was unavailable due to the fact that a certified air quality multi-pollutant monitoring station is not located in Great Falls to collect useful, quantitative and qualitative data – because that data could reveal that – not only are operations at Montana Renewables' seriously degrading Montana's air quality – but operations at Calumet, and other point-source pollution generators listed in this permit are most likely exceeding NAAQS standards, and contributing to adverse climate changes that are negatively impacting Montana's people, their health, local businesses and the environment.
DEQ has identified this section above as Public Comment #38.

EPA's Definition of Attainment/Unclassifiable

According to the EPA, https://www.epa.gov/criteria-air-pollutants/process-determine-whether-areas-meet-naaqs-designations-process [epa.gov], "*if the air quality in a geographic area meets or is cleaner than the national standard, it is called an attainment area (designated "attainment/unclassifiable"); areas that don't meet the national standard are called nonattainment areas. In some cases, EPA is not able to determine an area's status after evaluating the available information and those areas are designated "unclassifiable."*

Again, without certified air quality monitoring stations, no accurately and continuously collected qualitative and qualitative data exists to support the EPA's designation of Cascade County as "Attainment/Unclassifiable" or MDEQ's designation that companies in Great Falls are in compliance with the Montana Ambient Air Quality Standards MAAQS, or the EPA's NAAQS.

EPA's AirData Air Quality Monitoring System is shown at this site:

https://epa.maps.arcgis.com/apps/webappviewer/index.html?id=5f239fd3e72f424f98ef3d5def547eb5&extent=-146.2334,13.1913,-46.3896,56.5319 [epa.maps.arcgis.com].

Zooming into the map to review Air Quality Monitoring Stations in Montana, and using the layering system feature, reveals there are no active air quality monitoring stations in – or near – Great Falls, Montana.

In fact, there are no active air quality monitoring stations in, or near, Great Falls, to measure Carbon Monoxide, Lead, Lead TSP(LC), Lead - PM10, NO2, Ozone, PM10, PM2.5 or SO2.

Air Quality Monitoring Station Located at Great Falls High School

It is notable that in Great Falls, one inactive PM2.5 air quality monitoring station is located at Great Falls High School with data collected from years 2000 to 2009. This inactive site lies right in the path of the airborne plume of pollutants drifting across the river from Montana Renewables' and Calumet's refinery operations.

This is a critical location for air emissions data, because the high school sequesters students, teachers, faculty, staff and groundskeepers for several hours each day during the school year. Outdoor sporting events and athletic activities bring students, coaches, teachers, parents and siblings together, all of whom are exposed to even greater levels of criteria pollutants and hazardous air pollutants, and more vulnerable to the short-term and long-term adverse health impacts these pollutants can cause.

Additionally, this high school is most likely in a neighborhood surrounded by children who are actively playing outside on a daily basis, and engaging in physical activities that require greater air intake into their lungs and developing bodies. One need not be a doctor to know that health impacts from continuous saturation of criteria pollutants and hazardous air pollutants are not insignificant.

MDEQ should re-activate this air quality monitoring station to collect not only PM2.5 criteria pollutants, but expand this operation to include data for all criteria pollutants (SO2, NO2, Lead, PM10) and hazardous air pollutants (CO, VOCs, and Ozone).

According to an AI-generated response, "ground-level ozone is considered a hazardous air pollutant because it can cause serious health problems, particularly for individuals with respiratory issues, children, and the elderly. It is a major component of smog and can harm both human health and the environment."

Lastly, one active NCORE (Multi-pollutant Monitoring Network) site is situated near Helena, which is approximately 90 miles away from Great Falls. This site was specifically located in the wilderness to avoid all types of industrial pollutants as explained in this video produced by the MDEQ: https://www.youtube.com/watch?v=WRkUNExJHgs [youtube.com].

Clearly, the NCORE station is not a valid air quality monitoring station for any point-source pollution generator located in Great Falls, Montana.
DEQ has identified this section above as Public Comment #39.

The EJSCreen website (https://pedp-ejscreen.azurewebsites.net/ [pedp-ejscreen.azurewebsites.net]) shows high levels of Nitrogen Dioxides affecting areas directly across the Missouri River from the Montana Renewables/Calumet facilities. Click on Environmental Justice Indexes, and click on Nitrogen Dioxide to reveal quantities that range from the 50 to 100% percentile.

As explained by the EJ Indexes site:

"The NO2 EJ Index combines the environmental burden indicator for NO2 with the demographic index (an average of % low-income and % people of color) for each census block group.

The environmental burden indicator for NO2 measures how much surface level NO2 people might be exposed to in terms of annual average concentration in parts per billion. EJScreen presents surface level NO2 concentrations using percentile rank, ranging from 0 (lowest) to 100 (highest). This indicator does not designate compliance with the national ambient air quality standard for NO2. Source: Goddard Earth Sciences Data and Information Services Center [web.archive.org]."

Now, click on Diesel Particulate Matter, and a wide area completely surrounding the Montana Renewables/Calumet location shows the effect is in the range of the 50 to 80 percentile. Toxic Releases to Air show the same 50 to 80 percentile range.

The Great Falls High School is located in these areas, and this site represents possibly one of the best locations for the MDEQ to re-active and upgrade the existing air quality monitoring station to collect data for all criteria pollutants and hazardous air pollutants.

MDEQ Request for Clarification: Please clarify why the air quality monitoring station at Great Falls High School is inactive, and identify if this is the air quality monitoring that is not certified referred to in the DOE EA-2275 FoNSI. Please clarify why the MDEQ has failed to activate this monitoring station, and ensure it is certified so relevant data can be used.
DEQ has identified this section above as Public Comment #40.

Additionally, MDEQ, please install a certified, activated air quality monitoring station that can detect, measure and quantify all criteria pollutants and hazardous air pollutants being emitted by Montana Renewables, Calumet, and other point-source pollution generators located in Great Falls, Montana.

Private Property Impacts

Lastly, the AQP includes a list of Private Property Impacts As required by 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment. It states the following under ***21.***
Private Property Impacts:
DEQ has identified this section above as Public Comment #41.

"The proposed project would take place on private land owned by the applicant. DEQ's approval of MAQP #5263-03 would affect the applicant's real property. DEQ has determined, however, that the permit conditions are reasonably necessary to ensure compliance with applicable requirements under the CAA Act. ***Therefore, DEQ's approval of MAQP #5263-03 would not have private property-taking or damaging implications.****"*

Given the wind-borne emissions plume containing criteria pollutants and hazardous pollutants drifting around the clock (24/7/365 on average) from Montana Renewables and Calumet over various neighborhoods, and intermittently over other neighborhoods as the wind shifts, this last statement appear to be patently false. Obviously, homes in neighborhoods impacted by a continuous stench cannot be sold for top dollar. When people in these impacted neighborhoods try to sell their homes, they must be willing to accept far less than homes being sold in neighborhoods outside the plume area. I believe this represents a private property taking.

As further proof, almost any driver who is on the road between Calumet's refinery and Montana Renewables Max SAF location can attest to the overwhelming stench belching from these refinery stacks that completely engulfs vehicles as people are driving by. Neighborhoods that are suffering from the same stench are populated with people who are too poor to move, in general, to areas with cleaner air. The value of their property has to be significantly less than the value of properties located in areas that are not being adversely affected by criteria pollutants and hazardous air pollutants being emitted by both Calumet and Montana Renewables. The last statement, "***Therefore, DEQ's approval of MAQP #5263-03 would not have private property-taking or damaging implications,****"* appears to be highly questionable and patently false.
DEQ has identified this section above as Public Comment #42.

The AQP further states, *"VII. Private Property Impacts As required by 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment."*

1. *Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?* **X is in the YES box.**

2. *Does the action result in either a permanent or indefinite physical occupation of private property?* **X is in the NO box. This appears to be FALSE.**

3. *Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)* **X is in the NO box. This appears to be FALSE.**

4. *Does the action deprive the owner of all economically viable uses of the property?* **X is in the NO box. This appears to be FALSE.**

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 is in the NO box. This appears to be FALSE.**

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 is in the NO box. This appears to be FALSE.**

This project affects the economic value of private properties (homes and businesses) located in neighborhoods that are impacted by the plume of airborne emissions coming from Montana Renewables' Max SAF location, combined with Calumet's emissions. The questions above demonstrate a true need/requirement for an impacts analysis to be performed, and an additional in-depth impacts analysis to be performed prior to MDEQ's approval of this AQP.
DEQ has identified this section above as Public Comment #43.

Additional language found in the AQP states that:

Affected Environment *The proposed action increases the throughput of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production.*

Direct Impacts: *Proposed Action: Construction and operation of the proposed project would not be expected to affect the existing customs and values of the affected population. Therefore, no direct impacts to the existing social structures and mores of the affected population would be expected because of the proposed project.*

Secondary Impacts: *Proposed Action:* No secondary impacts to social structures and mores are anticipated because of the implementation of the project.

Cumulative Impacts: *Proposed Action:* No cumulative impacts to social structures and mores are anticipated because of the implementation of the project.

It should be noted that "Direct, Secondary and Cumulative Impacts" to existing social structures and mores in neighborhoods with populations of primarily poor people whose property is already being adversely impacted by this project's airborne emissions cannot be dismissed as non-existent. Further, expansion of this project will exacerbate the Direct, Secondary and Cumulative Impacts as the total volume emissions of criteria pollutants and hazardous air pollutants will increase over these neighborhoods.
DEQ has identified this section above as Public Comment #44.

MDEQ, please deny this AQP for Montana Renewables.
DEQ has identified this section above as Public Comment #45.

Comments received in comment referenced 5263-03_12_01_PUB_COM

I write in opposition to the MDEQ's PD for MAPQ #5263-03 for Montana Renewables. I oppose this on two main grounds:

- It's industry-written and unenforceable.
- It's incomplete without knowing with some certainty what the impact to water resources might be.

<u>Industry-written and Unenforceable</u>

I am a resident of Great Falls. I am not an engineer or scientist and cannot authoritatively speak to the hundreds of pages of documents submitted in the application, but I can read and understand a few things. One thing I most understood was that the language and crafting and preliminary approval of this application favor the industry (Montana Renewables in this case) every step of the way. It's rarely the environment that is given consideration, but more what is the most cost-effective way for the company to mitigate its effect on the environment. Yes, the ARMs do spell out the criteria, but the ARMs themselves sound like they are written by industry. It's performative diligence, but not real due diligence, and the MDEQ becomes a mere rubber stamp-room. OK, but does that in itself qualify as legitimate argument against the application? Perhaps not, but it should serve as a wake-up call to the public servants in MDEQ who are hired to protect the quality of our air (and water), and remind them not to take things always at face value just because the applicant has concluded so. Please do your duty.

However it may be finally worded, this permit is unenforceable. It puts the onus of monitoring and reporting on….hmmm, let's see…on the applicant! What could possibly go wrong there? As a Great Falls resident, I can relate to you a number of times within the last few years that the atmosphere in the city has been fouled by a god-awful, sulfide stench emanating from the Calumet operation—was it Calumet, was it MR? Who knows? Not me, not the city, not MDEQ. And that's just the emissions we can detect with our noses—I have not idea what else may have been wisping around. Calls to the city evoke only a shrug—city officials, choking on the same stench, cannot do anything, cannot get the refinery to admit anything, cannot resolve anything. That's current state of the industrial art.
There are virtually no independent air monitoring stations in the immediate area, and the PD includes no plans for establishing any. Without INDEPENDENT air monitoring, the expansion of SAF and associated gases and pollutants will continue unreported, unstopped, unenforceable. So…insist on independent monitoring in and around the city, else the entire application process becomes a charade.

(DEQ has identified this section above as Public Comment #46).

It's Incomplete

The MDEQ Environmental Assessment notes that "MRL proposes to install both a water conservation unit and a new PTU wastewater treatment system." The EA does not state WHEN that will be done (because MRL refuses to state when it might be done, other than at the very end of the expansion (see related DOE-EA for the project)—meaning that there may be **years** between the issuance of a permit and the construction of the treatment facility which DEQ anticipates will have an overall beneficial impact on water quality.It [quality.it] also states that wastewater could be hauled off-site for disposal, but does not mention **where**.

The EA does actually admit that the "Final disposition of waste products is **unknown** [*emphasis mine*] but off-site disposal of some quantity of wastewater is possible because system optimization success is unknown at this time." This is part of MDEQ's rationale for not requiring an EIS??? That it is UNKNOWN? That the systems have not yet been tested and verified? This is the basis for saying "All clear!"?? This should be the basis for saying WAIT, this is incomplete!

Perhaps you should ask where that wastewater is currently being hauled (Idaho) and where MRL would truly like to haul it (Pondera County, MT) if the EPA eventually permits it. While MRL has *proposed* building that wastewater treatment plant, they have not foresworn dumping it into depleted oil wells and into the Madison Aquifer. I quote from a MRL vice-president: **"Whether or not MT Renewables uses the Pondera County wells will be a business decision made in the future if/when the wells are permitted by EPA."**

The DOE-EA supporting the $1.44 billion loan for Max-SAF considered an EIS not necessary on the water impact side, since (according to the applicant and DOE) all water would be treated on-site. The expansion has already begun, and the tanker trucks hauling the wastewater away belie that stated assumption. So now, MDEQ, are you ready to dump the wastewater into Pondera County and the Madison Aquifer, also on their word?

The "system" is not complete; it's unknown; it needs at the very least an EIS, or if you approve this, it should be with conditions that the wastewater impacts be proven first, and withdrawn if contrary proof is found afterward.

(DEQ has identified this section above as Public Comment #47).

Table I.E.2. DEQ Responses to Public Comments on the PD

Public Comment Assigned Reference	**DEQ Response**	**Notes:**
Summary Bullet #1. Airborne pollutants (criteria pollutants and hazardous air pollutants) in the current Phase 1 already come close to exceeding EPA Prevention of Significant Deterioration (PSD), and Phase 2 expansion will increase these pollutants; the combined total surpass PSD Major Modification Significance Levels;	Major and Minor Stationary Source Determination, PSD Applicability. A source is classified as either a major stationary source or minor source with respect to PSD, based upon its potential to emit (PTE). Any listed new major stationary source will be subject to PSD if their PTE is equal to or greater than 100 tons/year for any regulated air pollutant. Existing, i.e., permitted, minor sources must first become a major stationary source or make a change that by itself constitutes a major stationary source, i.e., the change itself equals or exceeds 100 tons/year PTE, before becoming subject to PSD. Once an existing minor source has become major for PSD, any future changes that result in an emissions increase equal to or greater than the PSD significant emission rates or SERs codified at ARM 17.8.801(28), the change is subject to PSD. In this case, MRL is an existing minor source under MAQP #5263-02. Therefore, after issuance of this permit (MAQP #5263-03), because MRL's new PTE will be greater than 100 tons/year for CO, NOx, and VOCs, any future changes at	This comment is further addressed below. See all DEQ responses that include a PSD reference.

	MRL will be subject to PSD if the change increases emissions of any regulated pollutant by an amount equal to or greater than the SERs. The definitions at ARM 17.8.801(22)(a)(i) and (iii) clarifies this PSD applicability determination.	
Summary Bullet #2. The AQP application contains data which is in conflict with the DOE EA-2275 FoNSI findings for Montana Renewables' project;	The commenter frequently references the DOE FoNSI in reference to the Preliminary Determination. The issuance of the Montana Air Quality Permit is based upon the requirements established by the Administrative Rules of Montana (ARM 17.8). Specifically, permitting requirements are established at ARM 17.8.743 and application requirements under ARM 17.8.748. On July 15, 2025, MRL submitted their initial application for the current permit action (MaxSAF project). In response to DEQ comments on the initial air quality permit application, project details were modified by MRL including changes to the facility design, controls, and associated changes in emissions. Therefore, the DOE emission summary would not be expected to align with the emission inventory for permitted, allowable emissions. Regardless of whether the same consultant provided supporting information, the changes in design and control requirements result in different emission estimates.	This comment is further addressed below. See all DEQ responses that include a DOE FoNSI reference.
Summary Bullet #3. The AQP application contains data which is in conflict with EPA PSD Major Modification Significance Level standards;	As identified in Summary Bullet Comment #1 above, after issuance of the current permit action (MAQP #5263-03), any future facility modifications at MRL will be subject to PSD if the change exceeds applicable SERs.	This comment is further addressed below. See all DEQ responses that include a PSD reference.

Summary Bullet #4. Exceeding PSD levels triggers the requirement for a PSD permit in compliance with NAAQS and EPA guidelines;	As identified in Summary Bullet Comment #1 above, after issuance of the current permit action (MAQP #5263-03), any future changes at MRL will be subject to PSD if the change exceeds applicable SERs.	This comment is further addressed below. See all DEQ responses that include a PSD reference.
Summary Bullet #5. Affected areas lack proper air monitoring stations to ensure NAAQS, MAAQS and EPA compliance to protect human health and the environment.	Montana operates an ambient air quality monitoring network to determine compliance with the NAAQS. Individual stationary permitted sources generally do not trigger NAAQS monitoring requirements. Instead, the ambient air quality impacts analysis for permitted sources is generally established through dispersion modeling and associated analysis, as was the case for the current permit action.	This comment is further addressed below. See all DEQ responses that include a monitoring reference.
Summary Bullet #6. MDEQ should deny the AQP request to remove the Consent Decree (CD) (CD) (CIV-no 01-142LH) conditions and plantwide umbrella limits that were originally specific to the Calumet Montana Refining-Petroleum Refinery.	For the for the purposes of PSD, and in consultation with EPA, DEQ determined that previous limits established for equipment operating at the Calumet Refinery, do not directly carry over to the MRL facility. Rather, any previous limits applicable to equipment transferred from the Calumet Refinery to MRL, by default, maintain the established limits when operated by MRL; however, those limits are not PSD limits, as the MRL facility does not operate under the same industrial classification as the Calumet Refinery.	This comment is further addressed below. See Public Comment #9.
Summary Bullet #7. A continuous plume of airborne pollutants from Montana Renewables' biofuels processing is blanketing neighborhoods throughout Great Falls; this represents a "taking" that impacts the value of homes and businesses in areas adversely impacted by these airborne emissions; thus, better control technology equipment and solutions are needed to reduce the adverse impacts of these pollutants, as well as an impacts analysis to be performed.	The Private Property Assessment Act (§§ 2-10-101, et. seq) evaluates whether the permit results in takings and damages to the permitted entity and does not consider impacts to nearby home values. However, the Montana and federal Clean Air Acts necessarily include provisions to ensure compliance with, among other standards, the primary and secondary NAAQS. Primary NAAQS protect public health, including sensitive groups (kids, elderly, asthmatics), with an adequate safety margin, while Secondary NAAQS protect	This comment is further addressed below. See Public Comment #42 and Public Comment #45. Also see Public Comment #2, #4, #5, #6 and #8 on pollution control references (BACT).

	public welfare from harm to visibility, crops, animals, buildings, and ecosystems, covering broader effects like haze and material damage. Further, pursuant to ARM 17.8.752, MRL is required to use the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The permit also mandates MRL is required to meet visual standards for the discharge of visible pollutants from stack emissions at their site. The facility has permit requirements in place intended to ensure compliance with visual standards. Violations of permit conditions are subject to consideration for enforcement. Refineries, and facilities such as MRL, have controls in place that are often described as process, safety or emergency flares. These sources of emissions serve to reduce the risk to surrounding areas by combusting the off-gasses that otherwise would be vented to the atmosphere and thus prevent an unacceptable risk to the affected public.	
Specific Comments	**DEQ Response**	**Notes**
Public Comment #1. Generally covers PSD applicability.	DEQ will address this issue in multiple specific comments below in addition to the response provided here. As identified in Summary Comment #1 above, after issuance of the current permit action (MAQP #5263-03), any future modifications at MRL will be subject to PSD if the change exceeds applicable SERs. This means that MRL has surpassed the listed source PSD applicability threshold levels for multiple pollutants and thus any "future' proposed MRL projects will be evaluated for the pollutant increase levels that the commenter has referenced. The SERs for CO are 100 TPY, 40	The status of MRL falls under ARM 17.8.801(22)(a)(iii). See DEQ response titled Summary Bullet #1.

	TPY for NOx and 40 TPY for VOCs.	
Public Comment #2. Generally covers reference to the DOE FoNSI as compared to the Montana Air Quality Permit Application.	The commenter frequently references the DOE FoNSI in reference to the Preliminary Determination. The issuance of the Montana Air Quality Permit is based upon the requirements established by the Administrative Rules of Montana (ARM Title 17, Chapter 8). Specifically, permitting requirements are established at ARM 17.8.743 and application requirements under ARM 17.8.748. On July 15, 2025, MRL submitted their initial application for the current permit action (MaxSAF project). In response to DEQ comments on the initial air quality permit application, project details were modified by MRL including changes to the facility design, controls, and associated changes in emissions. Therefore, the DOE emission summary would not be expected to align with the emission inventory for permitted, allowable emissions. Regardless of whether the same consultant provided supporting information, the changes in design and control requirements result in different emission estimates	
Public Comment #3. Generally covers DOE FoNSI data as compared to the Montana Air Quality Permit Application.	As detailed in Summary Comment #1 and discussed in Public Comment #1 and Public Comment #2 above, referencing the acronym PSD can mean slightly different things without additional context. In this case, the current permit action is not subject to PSD, but following issuance of MAQP #5263-03, any future changes at MRL will be subject to PSD if the change exceeds applicable SERs.	

Public Comment #4. Generally covers PSD applicability.	The commenter is directed to Section III of the Permit Analysis titled BACT Analysis and Determination. The MaxSAF project was subject to requirements established pursuant to ARM 17.8.752, Emission Control Requirements. During the time from the initial submittal of the application on July 15, 2025, significant effort was expended by MRL to update the BACT analysis to comply with the instructions provided in Section 4.11 of the most recent version of the Stationary Source Permit Application. The application is available for review on DEQ's website under "Air," "Permitting and Operator Assistance," "Forms, Applications, Instructions, and Manuals." The inclusion of a robust BACT analysis, combined with a cumulative modeling analysis provided DEQ with the required information necessary to issue the Preliminary Determination on Montana Air Quality Permit #5263-03, determining that issuance of the permit will not cause or contribute to a NAAQS violation.	
Public Comment #5. Generally covers PSD applicability.	As discussed in Public Comment #1, and Public Comment #4, the MaxSAF project itself was not subject to a PSD analysis and a robust BACT analysis was conducted. When and if future projects trigger a PSD analysis (see response to Summary Comment #1), any additional elements of a PSD analysis would be required.	

Public Comment #6. Generally covers the DOE FoNSI report versus Montana Air Quality Permit Application information.	As discussed in Public Comment #2, the commenter referenced the DOE FoNSI report. The requirements for a complete air quality application are separate and distinct from information presented in the federal DOE's report that was prepared prior to the final facility design, including required controls, being finalized. For example, receptor modeling that may have been conducted for the DOE FoNSI report would not have included a change in permitted stack heights that occurred in response to DEQ comments on MRL's initial BACT analysis and determination and Modeling, i.e., Ambient Air Impacts Analysis. Therefore, as presented in the Permit Analysis, no sources at MRL were determined to have receptor exceedances above significant impacts levels (SILs) and thus, as permitted, would not be expected to cause or contribute to a NAAQS violation.	
Public Comment #7. Generally covers Title V applicability.	For the purposes of Title V Operating Permits, MRL and the Calumet Refinery are considered a single stationary source. However, for various reasons, and as allowed, MRL has chosen to apply for its own Title V Operating Permit #OP5263-00, which was issued final and effective on May 13, 2025. Title V Operating Permit #OP5263-00 incorporates the emitting units that existed under Montana Air Quality Permit #5263-02, issued final on November 9, 2023. Any additional emitting units and associated applicable requirements added under the current permit action (MAQP #5263-03) would be included in a modified Title V Operating Permit. An application for modification of the existing Title V Operating Permit must be submitted to DEQ within 12-months of the equipment	

	permitted under the current permit action (MAQP #5263-03) commencing operation.	
Public Comment #8. Generally covers an explanation of Title V applicability related to both MRL and Calumet.	As discussed in the response to Public Comment #7, above, both MRL and Calumet operate under their own respective Title V Operating permits, but are considered a single stationary source for the purposes of Title V. Each facility also operates under their own Montana Air Quality Permit. Calumet currently operates under MAQP #2161-40 and MRL currently operates under MAQP #5263-02. If issued, MRL would operate under the current permit action (MAQP #5263-03). These permits incorporate BACT as well as state and federal requirements applicable to each facility's respective SIC code.	
Public Comment #9. Generally covers applicability of Consent Decree (CIV-no-01-142LH).	Elements of the Calumet Consent Decree (CIV-no-01-142LH) were established specifically for the Calumet Refinery and were largely incorporated under the PSD rules because the Calumet Refinery is an existing PSD source. For the purposes of PSD, sources would be considered the same stationary source if they meet *all* of the following three criteria: 1) the sources are under common ownership and control, 2) they are co-located on contiguous and adjacent property, and 3) they share the same industrial category (SIC codes). Calumet and MRL are under common ownership and control and are located adjacent to each other, but they operate under different SIC Codes. Therefore, for the purposes of PSD, they are considered separate and distinct sources and are thus subject to their own PSD applicability determinations. The Calumet Consent Decree requirements are not included in the MRL Operating Permit #OP5263-00,	

	which is unrelated to the current MaxSAF project, and are not incorporated as specific requirements within MAQP#5263-03. As detailed in Summary Comment #1, the current permit action is not subject to PSD, but following issuance of MAQP #5263-03, any future changes at MRL will be subject to PSD if the change exceeds applicable SERs.	
Public Comment #10. Generally covers PSD applicability.	As discussed in Summary Comment #1, Public Comment #1 and Public Comment #3, MRL is an existing minor source under MAQP #5263-02. After issuance of the current permit action (MAQP #5263-03), because MRL's new PTE will be greater than 100 tons/year for CO and VOCs, any future changes at MRL will be subject to PSD if the change increases emissions of any regulated pollutant by an amount equal to or greater than the SERs. The definitions at ARM 17.8.801(22)(a)(i) and (iii) clarifies this PSD applicability determination.	
Public Comment #11. Generally covers DOE FoNSI vs Air Quality Permit Application information for NOx PSD applicability.	As discussed in Summary Comment #1 and Public Comment #1, MRL is an existing minor source under MAQP #5263-02. However, after issuance of this permit (MAQP #5263-03), because MRL's new PTE will be greater than 100 tons/year for CO, NOx, and VOCs, any future changes at MRL will be subject to PSD if the change increases emissions of any regulated pollutant by an amount equal to or greater than the SERs. The definitions at ARM 17.8.801(22)(a)(i) and (iii) clarifies this PSD applicability determination.	
Public Comment #12. Generally covers DOE FoNSI vs Air Quality Permit Application	See DEQ response directly above for Public Comment #11.	

information for VOC PSD applicability.		
Public Comment #13. Generally covers DOE FoNSI vs Air Quality Permit Application information for PM10 PSD applicability.	See DEQ response above for Public Comment #11. Also, Pursuant to PSD, if a new major source or major modification triggers PSD for one pollutant (by exceeding its significant emissions threshold or being a major source), it becomes subject to PSD review for all other regulated pollutants emitted in significant amounts, even if those other pollutants alone wouldn't trigger it—this is termed the, "major for one, major for all" principle, ensuring comprehensive air quality protection under the PSD program. MRL is currently not above the major PSD threshold for any PM species.	
Public Comment #14. Generally covers DOE FoNSI vs Air Quality Permit Application information for PM2.5 PSD applicability.	See DEQ response above for Public Comment #11 and #13, above. MRL is currently not above the major PSD threshold for any PM species.	
Public Comment #15. Generally covers DOE FoNSI vs Air Quality Permit Application information for CO PSD applicability.	See DEQ response above for Public Comment #11. Also, see Public Comment #6 explaining that the Air Quality Application process is separate and distinct from the DOE FoNSI report.	
Public Comment #16. Generally covers DOE FoNSI vs Air Quality Permit Application information.	See DEQ response above for Public Comment #11. Also see Public Comment #6 explaining that the Air Quality Application process is separate and distinct from the DOE FoNSI report.	
Public Comment #17. Generally covers DOE FoNSI vs Air Quality Permit Application information.	See DEQ response above for Public Comment #11. DEQ has no plans to inform the DOE-LPO team as project details were modified after the initial MaxSAF submittal. The Preliminary Determination and subsequent permit issuances are available to any stakeholders for review.	

Public Comment #18. Generally covers DOE FoNSI vs Air Quality Permit Application information for HAPs	DEQ has no plans to inform the DOE-LPO team as project details were modified after the initial MaxSAF submittal. The Preliminary Determination and subsequent permit issuances are available to any stakeholders for review. According to the Emission Inventory submitted to DEQ, MRL will be a major source for HAPs. Therefore, if MRL was not subject to Title V Permitting for any other reason, the single HAP exceeding 10 tons per year would have triggered the requirement for a Title V Operating Permit.	
Public Comment #19. Generally covers DOE FoNSI vs Air Quality Permit Application information.	As discussed in other responses above, requirements for a complete Air Quality Permit application are separate and distinct from the DOE FoNSI report. Further, project details were modified after the initial air quality permit application was submitted on July 15, 2025. On July 15, 2025, MRL submitted their initial application for the current permit action (MaxSAF project). In response to DEQ comments on the initial air quality permit application, project details were modified by MRL including changes to the facility design, controls, and associated changes in emissions. Therefore, the DOE emission summary would not be expected to align with the emission inventory for permitted, allowable emissions.	

Public Comment #20. Generally covers PSD applicability.	As discussed in other responses above, the project itself does not exceed the PSD applicability threshold for a listed source (100 tpy) for any criteria pollutant, and therefore the MaxSAF project is not considered a major PSD source, as defined by ARM 17.8.801(22)(a)(i) and (iii). The commenter is correct that NOx and VOCs contribute to ozone, which is why ozone impacts were characterized using EPA's Modeled Emission Rates for Precursors (MERPs) tool in the Ambient Air Impact Analysis section of the permit. Ozone analysis was triggered by the project's VOC emission increases, and calculated ozone impacts account for both VOC and NOx contribution. These results are listed above in Table VI-5 of the permit. Some portions of PM2.5 are also secondarily formed, and the secondary PM2.5 impact is listed in the same section and included in subsequent PM2.5 modeling results. Thus, to the commenter's claims that ozone and fine particles were dismissed as not being relevant within the permit analysis, it should be noted that ozone and secondary PM2.5 ambient impacts were calculated, evaluated, and discussed in the permit analysis. Further, the permit analysis does not claim that ozone and PM2.5 from the project do not contribute to consuming any portion of the NAAQS, but rather, they do not cause or contribute to a violation of the NAAQS. This determination is a requirement for permit issuance pursuant to ARM 17.8.749.	

Public Comment #21. Generally covers Title V and PSD applicability.	The reference to 40 CFR 52.21 defines that a source that is major for VOCs or NOx shall also be major for ozone and is subject to PSD review. As noted previously, if a new major source or major modification triggers PSD for one pollutant (by exceeding its significant emissions threshold or being a major source), it becomes subject to PSD review for all other regulated pollutants emitted in significant amounts, even if those other pollutants alone wouldn't trigger it—this is termed the, “major for one, major for all” principle, ensuring comprehensive air quality protection in clean areas. While the MaxSAF project does not trigger a PSD permit or PSD analysis, pursuant to ARM 17.8.752, the permit did incorporate a robust BACT analysis as required under Montana BACT. Future projects that trigger a PSD analysis would follow PSD requirements (see response to Summary Comment #1). Additionally, the commenter claims that MaxSAF project NOx, VOC, and ozone emissions violate the NAAQS. As demonstrated in Section VI of the Permit Analysis titled Ambient Air Impacts Analysis, impacts from the MaxSAF project emissions for each of these pollutants were determined to not cause or contribute to a violation of any applicable NAAQS.	

Public Comment #22. Generally covers what constitutes a HAP.	A slightly updated Emission Inventory Table has been incorporated into Section IV of the Permit Analysis of the Department Decision on MAQP #5263-03, including identifying hexane as the largest single HAP emission. Further, the corrected version of the emission inventory included additional emission reductions based on control improvements that were incorporated/proposed after the initial application submittal, but incorrectly applied in the Preliminary Determination. The updated version of the emission inventory documents pollutant decreases primarily for NOx, and VOCs. Additionally, DEQ included the emission inventory calculations for the new combustion units, H-4103, H-5801 and the CoGen Unit fired on both naphtha and natural gas. These three units make up most of the emission increases associated with the MaxSAF project. Finally, EPA does not designate either CO or VOCs as HAPs Under the Clean Air Act, as the commenter incorrectly suggests.	
Public Comment #23. Generally covers what constitutes a HAP.	EPA does not designate either CO or VOCs as a HAP under the Clean Air Act. A current list of regulated HAPs is codified at 40 CFR 63, Subpart C, and readily available on EPA's website. Where present, and for the purposes of permitting, DEQ generally summarizes the total combination of HAPs emitted in tons per year if more than one HAP is emitted. As stated in other responses, MRL already holds Title V Operating Permit OP#5263-00; therefore, the presence of HAPs emissions is incorporated into existing permit conditions for the site.	

Public Comment #24. Generally asks for HAP speciation.	DEQ notes that n-hexane is the primary HAP present, specifies this detail in the emission inventory, and incorporates it as a HAP pollutant in the Environmental Assessment, which analyzes potential impacts from the proposed action (MAQP #5263-03).	
Public Comment #25. Generally identifies what permitting HAP thresholds trigger under Clean Air Act rules.	As noted in other responses, whether a source is major for a single or cumulative HAPs emissions is one of the criteria for determining Title V applicability. Title V is also triggered when emissions of any regulated pollutant equal or exceed 100 tons/year. MRL is subject to Title V because they are major for HAPs and other regulated pollutants. MRL already holds Operating Permit #OP5263-00.	
Public Comment #26. Generally covers Title V and PSD applicability.	As discussed in other responses above, requirements for a complete Air Quality Permit application are separate and distinct from the DOE FoNSI report. Further, in response to DEQ comments, project details were modified after submittal of the initial air quality permit application on July 15, 2025. In response to DEQ comments on the initial air quality permit application, project details were modified by MRL including changes to the facility design, controls, and associated changes in emissions. Therefore, the DOE emission summary would not be expected to align with the emission inventory for permitted, allowable emissions. Again, MRL already holds Operating Permit OP5263-00, so the presence of HAP emissions does not necessarily trigger additional permit requirements.	

Public Comment #27. Generally clarifies pollutant specific demonstrations for modeling.	The initial application submitted by MRL on July 15, 2025, did not include a cumulative modeling analysis. However, based on review of the initial application, DEQ requested a full (i.e., cumulative) modeling demonstration for PM2.5 and NOx, in part because analysis of the MaxSAF project's maximum impacts (i.e., ground-level concentrations) nearly exceeded significant impact levels (SILs) for the annual PM2.5 and 1-hour NO2 standard. SIL values are thresholds below which impacts are considered statistically insignificant thereby demonstrating that the modeled emissions could not cause or contribute to a violation of the NAAQS. However, a significant impact analysis only accounts for impacts from the project emission increases (i.e., MaxSAF project-only impacts). Because modeling of the existing MRL facility and nearby sources in the Great Falls area had not been recently conducted (for MRL or any other permit action), DEQ was concerned that cumulatively the MRL facility, including the MaxSAF project and coupled with all other nearby sources may have significant impacts within the Great Falls airshed. Demonstrating significant impacts alone does not mean that a NAAQS has been violated. However, if the cumulative impacts of MRL and all nearby sources were to violate the NAAQS in a model demonstration, *and* MRL had a significant impact at the time and location of the violation, then emissions from MRL's proposed action would be deemed to cause or contribute to a violation of the NAAQS. In that case, and pursuant to ARM 17.8.749, the permit would not be issued to MRL without first establishing	

	enforceable conditions and limits to remedy the NAAQS violation. Thus, because the MaxSAF project-only emissions nearly exceeded significance levels for PM2.5 and NO2, and DEQ did not have access to a recent cumulative modeling analysis for the affected area, DEQ required a cumulative modeling analysis for the current permit action (MAQP #5263-03). The required cumulative modeling analysis included all sources of those pollutants at MRL as well as all other sources of these pollutants in the Great Falls area, to demonstrate NAAQS compliance. Cumulative modeling for CO and VOCs (modeled as ozone using MERPs tool) was not required because MaxSAF project emissions, which exceed the existing facility emissions, have ambient impacts far below the SILs (see Table VI-5 and preceding paragraph). Further, PM10 modeling was not requested because modeling applicability was determined based on thresholds that are listed in Montana's Modeling Guideline. Facility-wide PM10 emissions, including the MaxSAF project, would be 37.3 tpy, which is less than the applicable 50 tpy modeling threshold. However, importantly, PM10 emission totals are effectively the same as PM2.5; therefore, the modeling results for the 24-hour and Annual PM2.5 NAAQS can appropriately be used as a surrogate to estimate PM10 impacts. As demonstrated in the Ambient Air Impact Analysis (Section VI) MRL does not cause or contribute to a violation of the PM2.5 NAAQS and, by default, would not be expected to cause or contribute to a PM10 NAAQS violation.	

Public Comment #28. Generally covers DOE FoNSI report vs Air Quality Permit Application information.	As discussed in other responses above, requirements for a complete Air Quality Permit application are separate and distinct from the DOE FoNSI report. Further, project details were modified in response to DEQ comments after the initial air quality permit application was submitted on July 15, 2025. In response to DEQ comments on the initial air quality permit application, project details were modified by MRL including changes to the facility design, controls, and associated changes in emissions. Therefore, the DOE emission summary would not be expected to align with the emission inventory for permitted, allowable emissions. Further, the MaxSAF project did not trigger a PSD permit or PSD analysis (see response to Summary Comment #1).	
Public Comment #29. Generally covers BACT applicability.	See DEQ response to Public Comment #4.	
Public Comment #30. Generally covers NAAQS Monitoring.	The Great Falls PM2.5 monitor is not currently designated as a primary NAAQS monitor, meaning that it is not used for regulatory determinations of attainment status, such as the 2024 revised annual PM2.5 NAAQS. This is partially a legacy of the monitor's location, which is/has been located within a shelter originally sited for CO monitoring related to the historic Great Falls CO nonattainment area that was redesignated maintenance/attainment in 2002. Due to the monitoring site's location adjacent to a highway, 24-hr and annual PM2.5 averages tend to be elevated. However, the monitor is still maintained and held to rigorous quality assurance and quality control (QA/QC) standards by DEQ's Air Quality Bureau, (AQB), Air Research and Monitoring Section (ARMS). Further, the monitor is required	

	per Table D-5 of Appendix D to 40 CFR Part 58, which defines the number of monitors that must operate in a federally designated metropolitan statistical area (MSA). Great Falls is 1 of 5 MSAs in Montana. DEQ's ARMS and EPA have initiated discussions on re-locating the monitor to be more representative of neighborhood-scale impacts, but even in its current location it continues to record impacts from road traffic, industrial activities, and especially summer wildfire smoke. The monitor records data hourly, and concentrations (as well as health impacts and recommended actions) may be viewed on DEQ's Today's Air website (todaysair.mtdeq.us).	
Public Comment #31. Generally covers proposing non-regulatory monitors.	DEQ acknowledges that there are new technologies and cheaper monitors becoming available. In fact, DEQ has begun implementing these technologies where appropriate. However, DEQ cannot support infinite numbers of monitoring stations due to the time and resources necessary to maintain them and the cost to purchase and operate the equipment. The existing PM2.5 monitoring site in Great Falls may not be well suited to capture the impacts from the permitted facility all the time. This limitation, however, is why ambient air impact analyses rely on dispersion modeling for the purposes of permitting industrial sources of air pollution. The modeling demonstration prepared for MAQP #5263-03 effectively assumes that there are thousands of monitors spread across the Great Falls area at regular intervals. The modeling results demonstrate that the MaxSAF project and the MRL facility as a whole, with consideration for all other sources in the affected area, complies with the NAAQS at all	

	of these modeled receptor points (i.e., simulated monitoring locations).	
Public Comment #32. Generally covers NAAQS designation protocols.	When a new or revised NAAQS is promulgated, all areas of the state must be designated (attainment, unclassifiable, or nonattainment), with final determinations made by EPA. This is generally done on a county-by-county basis across the state. In cases where ambient regulatory monitoring data demonstrates a violation of the NAAQS, a county, or portions of a county, may be designated as non-attainment, and the non-attainment boundary would be based on supporting analysis such as modeling, meteorology, and source apportionment, to name a few. In areas where ambient monitoring data demonstrate compliance with the NAAQS or areas where regulatory monitoring data is incomplete or absent, the area is designated as unclassifiable or attainment. Whether an area is required to have ambient air quality monitors operated by DEQ is based on the requirements of 40 CFR 58, Appendix D. These requirements outline how many monitors, if any, are required per pollutant. Currently, only PM2.5 monitoring is required in the Great Falls area, in part due to recent and historical measured PM2.5 concentrations. Therefore, as discussed previously, this monitor is not currently used for regulatory determinations such as NAAQS designations, because of issues related to siting criteria. Great Falls has a history with monitoring for CO, SO2, and PM10 in addition to PM2.5. The last non-attainment area (NAA) designation in Great Falls was for CO, but subsequent monitoring data demonstrated the NAA complies with the NAAQS. Therefore, the CO NAA was	

	redesignated by EPA to attainment on July 8, 2002, and CO monitoring was discontinued in 2011 due to consistently low monitored concentrations that were approximately 10% or less of the NAAQS. Other pollutant monitoring was also discontinued because it was no longer required, and measured concentrations demonstrated continued compliance with the NAAQS. Therefore, Great Falls is currently designated unclassifiable or attainment for all pollutants, as documented in 40 CFR Part 52. As it relates to this permit action, the ambient air impacts analysis and the modeling results contained within demonstrate that the MaxSAF project emissions increases would not be expected to jeopardize Great Falls' compliance status with all applicable NAAQS.	
Public Comment #33. Generally covers NAAQS for pollutants.	NAAQS are set for all criteria pollutants. NAAQS are not established for HAPs. Therefore, there is no means to regulate HAPs in the same fashion. Most often, HAPs are regulated through other on-site strategies, such as emission controls or in some cases a federal requirement specific to the facility's SIC Code may require HAPs reductions. Montana does not regulate Air Toxics in the same fashion as some other states.	
Public Comment #34. Generally covers NAAQS and HAP definitions.	CO and VOCs are not considered HAPs under the Clean Air Act. As demonstrated in the Ambient Air Impact Analysis (Section VI), emissions from the MaxSAF project and MRL facility-wide emissions, do not exceed any NAAQS nor do they cause or contribute to a violation of any NAAQS. The commenter requests missing emissions data, which may be found in the updated table in Section IV of the Permit Analysis. The existing MRL	

	emissions (pre-MaxSAF project) are listed, although it should be noted that these emissions represent the facilities potential to emit. Actual emission rates between 2022 and 2024 would've been lower and these values are available from DEQ, upon formal request.	
Public Comment #35. Generally covers NAAQS compliance.	Based on MRL's emissions, Table VI-1 lists the relevant standards that required modeling based on the applicability thresholds provided by Montana's Modeling Guideline (2007). The table lists the significant impact level (SIL) concentrations that the MaxSAF project ambient impacts were compared against. Those results are found in Table VI-5 which indicates the project emissions are insignificant and therefore do not require any further modeling to demonstrate compliance with the NAAQS. This is standard practice in modeling for both minor and major PSD sources. Table VI-1 also lists the NAAQS and Montana Ambient Air Quality Standards or MAAQS, which, due to concerns over the project emissions' proximity to the SILs, were utilized in a cumulative modeling demonstration. Those results are listed in Table VI-9 and further clarified in Table VI-10 Finally, a Class II increment analysis was performed for the NO2 annual averaging period because the minor-source baseline date for NOx was triggered within Cascade County in 1993 (thus making MRL an increment-consuming source). The increment analysis results are displayed in Table VI-11 The results demonstrate that MRL, and the proposed MaxSAF project, complies with all applicable NAAQS/MAAQS.	

Public Comment #36. Generally covers modeling assumptions incorporated.	The modeling analysis presented in the Ambient Air Impact Analysis (Section VI) assumes that all new and existing emission sources at MRL operate every hour of all 5 years in the modeling timeframe. The only exception is for two existing boilers and generators that are only used in the winter months and account for less than 2% of the modeled MRL emissions. Otherwise, the modeling demonstration does not take advantage of any simulated maintenance shutdowns of any emitting sources.	
Public Comment #37. Generally inquires about lead permitting applicability.	Because MRL operates with some similar process units to those used by petroleum refineries, DEQ reviewed the four permitted petroleum refineries in Montana for emission inventory understanding, as it relates to lead emissions. None of the four refineries report lead emissions to DEQ because any lead present is likely to remain soluble as a lead species within the wastewater and not be emitted to the atmosphere. Like the permitted petroleum refineries, MRL does not incorporate processes that are believed to "volatize" lead, which would make it an air emission or have a high enough lead concentration in wastewater that would result in enough fugitive air emissions to trigger any additional permitting requirements. Any lead that may be present in the wastewater being discharged to the POTW, may trigger review by the City of Great Falls. These requirements would be regulated by the applicable Montana Pollution Discharge Elimination System or MPDES permit.	

Public Comment #38. Generally covers monitoring.	As discussed in previous responses, modeling is a surrogate compliance demonstration commonly conducted in lieu of monitoring for facility-specific impacts. Monitoring, as a technology, is limited in that it only collects air where the monitor is sited, but a modeling demonstration calculates ambient concentrations at tens of thousands of simulated monitors, i.e., receptors. Dispersion modeling is a long-time and trusted quantitative method for predicting and replicating pollutant concentrations that may otherwise be missed by an ambient monitor. The modeling results contained in Section VI of the Permit Analysis titled Ambient Air Impact Analysis includes analysis of all nearby facilities within a 50km radius of the MRL facility. The initial cumulative impacts results demonstrate that MRL's facility-wide emissions do not cause or contribute to a violation of the NAAQS. However, there were two locations where NAAQS violations appeared to occur at receptors located near two nearby facilities. As discussed in the Ambient Air Impact Analysis, it is clear these modeled NAAQS violations were due to extremely conservative estimates of fugitive dust (PM2.5) release parameters at the affected nearby sources. In coordination with the two facilities in question, more accurate (though still conservative) parameters were developed, and the model was re-run. The cumulative results illustrated that the maximum modeled concentration was 93% or less of each applicable NAAQS. It's worth noting that the background concentrations account for some industrial activity already, so by explicitly	

	modeling all facilities within the Great Falls area, there is likely an overestimation of impacts occurring within the modeling domain. Please also see response to comment #32.	
Public Comment #39. Generally covers monitoring.	There is an active PM2.5 monitoring station located at 2nd St/Overlook Dr and 10th Avenue in Great Falls (AQS ID: 30-013-0001; lat/lon: 47.49432, -111.30332). Per a previous response, the monitor records data hourly, and concentrations (as well as health impacts and recommended actions) may be viewed on DEQ's Today's Air website (todaysair.mtdeq.us). As previously discussed, DEQ is currently working with EPA to relocate this active monitor to a more suitable location that meets all siting criteria for regulatory monitoring. However, the active monitor's location is likely to be impacted by emissions from MRL due to the prevailing southwesterly (southwest to northeast) wind direction in the affected area. Concentration contour plots established for the cumulative emissions impacts analysis demonstrate that the emissions predicted to reach ground level stretch to the northeast as well as to the southwest. Thus, the active monitor's location south and slightly west of MRL, though slightly further away than the previous PM2.5 monitoring location, is not necessarily less suited to capture impacts from industrial activity in Great Falls. The commenter also mentions the NCore monitor. The NCore site is not used in the permit's ambient impact analysis because the ambient monitoring data from Great Falls and Lewistown is more representative for the analysis performed.	

Public Comment #40. Generally covers monitoring.	The PM2.5 monitor near Great Falls High School was discontinued in a consolidation effort to have PM2.5 and CO monitoring occur at the same location, where PM2.5 monitoring is currently conducted. The Great Falls PM2.5 monitoring referenced in DOE EA-2275 FoNSI is the currently operating Great Falls (Overlook Park) Monitor (AQS ID: 30-013-0001). As discussed in the response to comment #30, this monitor no longer meets siting criteria. While not designated as a primary NAAQS monitor, DEQ's ARMS effectively operates the station as a regulatory site thereby collecting accurate data for use in permitting decisions, such as the current permit action. This real time data is readily available for public review (see todaysair.mtdeq.us).	
Public Comment #41. Generally covers Private Property Impacts	Please see response to public comment #38.	
Public Comment #42. Generally covers Private Property Impacts	The commenter noted an example of stench of odors in the area. DEQ does not have authority to regulate odors, and the smell of sulfides does not constitute a violation. This permitting action included an ambient air quality impacts analysis, which demonstrates the MRL facility, including the proposed emission increases under the MaxSAF project, will not cause or contribute to a violation of the NAAQS for any pollutant. The permit includes enforceable conditions regarding permit limits such as equipment that will be required to have continuous emission monitors or CEMS coupled with initial and periodic source testing using EPA-approved methods. Issuance of a Montana Air Quality Permit is largely based upon the applicable requirements	

	of ARM 17.8.748. From the date an application for a Montana Air Quality Permit is deemed complete, DEQ has 40 days to issue their Preliminary Determination, and must issue the Department Decision within 60 days after the application was deemed complete. On October 17, 2025, DEQ determined the application for the current permit action was complete, and that the facility will not cause or contribute to a violation of the NAAQS. Therefore, pursuant to ARM 17.8.749, DEQ is obligated to issue MAQP #5263-03 for MRL's MaxSAF project.	
Public Comment #43. Generally covers Private Property Impacts.	The Private Property Assessment Act (PPAA, §§ 2-10-101, et. seq) evaluates whether the permit results in takings and damages to the permitted entity and does not consider impacts to nearby home values. However, the Montana and federal Clean Air Acts necessarily include provisions to ensure compliance with, among other standards, the primary and secondary NAAQS. Primary NAAQS protect public health, including sensitive groups (kids, elderly, asthmatics), with an adequate safety margin, while Secondary NAAQS protect public welfare from harm to visibility, crops, animals, buildings, and ecosystems, covering broader effects like haze and material damage. The process for obtaining a modification to an air quality permit begins with a public notice made by the facility for the proposed project. MRL met this requirement through a posting in the Great Falls Tribune. The facility already held MAQP #5263-02. This action would serve to expand the existing production of renewable fuels but is very similar to the existing production at the facility. The requirements for obtaining a Montana Air Quality Permit have	

	been followed to date, as have the issuance of a Draft Environmental Assessment. Under the Montana Environmental Policy Act (MEPA) potential impacts have been identified and disclosed. A reduction in property values near the MRL facility is not subject to review under the PPAA and such impacts have been appropriately identified and disclosed pursuant to the applicable requirements of MEPA.	
Public Comment #44. Generally covers the EA resource area "social structures and mores".	The MaxSAF project expansion of existing MRL operations triggered a BACT analysis and determination as well as additional monitoring and controls that serve to minimize and document the release of air pollutants from MRL operations. Any emission increases from this project are better described under other Resource Areas within the Environmental Assessment, such "Air Quality."	
Public Comment #45. Requests Air Quality Permit not be issued.	DEQ determined the application was complete as of October 17, 2025. From that date, DEQ had 40 days to issue a Preliminary Determination, which was issued in a timely manner on November 14, 2025. Any permit or EA updates resulting from comments received on the Preliminary Determination have been incorporated into the Department Decision being issued. MRL has met all requirements for receiving an Air Quality Permit; therefore, pursuant to the applicable requirements of ARM 17.8.749, DEQ is obligated to issue a Department Decision for the Max SAF project.	

Public Comment #46. Generally covers Permit Enforceability.	Please see any response above with "monitoring" identified in the general description which describes how monitoring requirements are established under the Clean Air Act. The commenter noted an example of "sulfide stench" in the area. DEQ does not have authority to regulate odors, and the smell of sulfides does not necessarily constitute a violation. This permitting action required an ambient air quality analysis which demonstrated the facility, including the proposed emission increases associated with the MaxSAF project, will not cause or contribute to a violation of the NAAQS for any pollutant. The permit includes enforceable conditions and limits, such as equipment that must use continuous emission monitors with initial and periodic EPA method testing. The issuance of a Montana Air Quality Permit is largely based upon a demonstration of compliance with ARM 17.8.748. When applications are determined to be complete, DEQ has 40 days upon which to issue a preliminary Determination and must issue the Department Decision within 60 days after the application was deemed complete. On October 17, 2025, DEQ determined the application for the current permit action was complete, and that the facility will not cause or contribute to a violation of the NAAQS. Therefore, DEQ is obligated to issue the Department Decision for the proposed MaxSAF project.	

Public Comment #47. Generally covers Wastewater from MRL	As stated in the EA, the MaxSAF project includes infrastructure for expanding the processing of wastewater including a water conservation unit and new PTU wastewater pretreatment system. Based on relevant information provided by MRL, DEQ believes these efforts will serve to maximize the use of water on-site and provide for more consistent handling of wastewater. However, DEQ also understands that continued discharge of wastewater to the publicly operated treatment works (POTW) into the Great Falls Wastewater Plant is likely, and that off-site shipping of wastewater may continue to occur. The disposal of wastewater is not an activity regulated by MAQP #5263-03; rather, the disposal of wastewater must comply with the Clean Water Act and the federal Resource Conservation and Recovery Act or RCRA waste disposal regulations. MRL must comply with all applicable federal and state requirements, including those regulations applicable to wastewater and wastewater treatment.	

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 (DEQ). Upon request, DEQ 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 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.

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.*, 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 DEQ upon request.

4. 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.

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.

   d. 40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

   e. 40 CFR 60, Subpart KKKK–Standards of Performance for Stationary Combustion Turbines.

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 YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

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

   e. 40 CFR 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

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

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

2. ARM 17.8.402 Requirements. 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 DEQ. 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 DEQ by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by DEQ. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

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

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

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

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify, or use any air contaminant sources that have the 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 July 24, 2025, 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 DEQ at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving 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 DEQ's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. ARM 17.8.760 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 DEQ.

16. 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, 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.

With the PSD threshold being 100 tpy for a chemical manufacturing plant (SIC Code 2869, Industrial Organic Chemicals, Not Elsewhere Classified), following permit issuance MRL will be above the PSD threshold triggering thereby triggering the appropriate PSD analysis depending upon whether future project emission increases are determined to be significant increases or minor increases under the PSD program.

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 #5263-03 for MRL, the following conclusions were made:

a. The facility's PTE for Carbon Monoxide (CO), Oxides of nitrogen (NOx), and volatile organic compounds (VOCs) is greater than 100 tpy.

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, Subpart Kb, Subpart IIII, and Subpart KKKK.

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

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, DEQ determined that MRL is subject to the Title V operating permit program. Because there is common ownership and adjacent/contiguous property, Title V applicability is assumed as long as the current ownership structure exists.

III. BACT Analysis and 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. DEQ reviewed these methods, as well as previous BACT determinations.

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

MRL provided a BACT analysis for the permitting action because the current permit action is subject to ARM 17.8.752. The BACT analysis follows a process similar to the traditional 1990 draft New Source Review (NSR) five step BACT methodology. The analysis will be presented using the following steps for each pollutant and emitting unit.

Step 1: Identify All Available Control Technologies
Step 2: Eliminate Technically Infeasible Control Options
Step 3: Rank Remaining Control Technologies by Control Effectiveness
Step 4: Evaluate Most Effective Controls and Document Results
Step 5: Select BACT

Maximum Air Pollution Control Capability

Table III-1 lists all the emitting units by pollutant with a BACT analysis submitted for the MaxSAF Project.

Table III-1
Control Technology Evaluation: Emission Units and Associated Pollutants

Source	PM_{FIL}	PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO
New RFU Heater (H-4103)	X	X	X	X	X	X	X
New Reformer Heater (H-5801)	X	X	X	X	X	X	X
New Cogeneration Plant (Natural Gas)	X	X	X	X	X	X	X
New Cogeneration Plant (Renewable Naphtha)	X	X	X	X	X	X	X
SSM Limits for Existing Heaters (H-4101, H-4102, H-3815A/B, and H-4601)	X	X	X	X	X	X	X
Existing Storage Tank #29 with Updated Service/Throughput						X	
Existing Storage Tank #116 with Updated Service/Throughput						X	
Existing Storage Tank #128 with Updated Service/Throughput						X	
Existing Renewable Feed Storage Tank #301 with Updated Throughput						X	
Existing Renewable Feed Storage Tank #302 with Updated Throughput						X	
Existing Renewable Feed Storage Tank #303 with Updated Throughput						X	
Existing Renewable Naphtha Storage Tank #304 with Updated Throughput						X	
Existing Storage Tank #305 with Updated Service/Throughput						X	
Existing Storage Tank #306 with Updated Service/Throughput						X	
Existing Storage Tank #307 with Updated Service/Throughput						X	
Existing Storage Tank #308 with Updated Service/Throughput						X	
New Fuel Product Storage Tank #309						X	
New Fuel Product Storage Tank #310						X	
New Fuel Product Storage Tank #311						X	
New Renewable Feed Storage Tank #312						X	
New Renewable Feed Storage Tank #313						X	
New Renewable Feed Storage Tank #314						X	
Existing PTU Wastewater Tank #4201 with Updated Throughput						X	
New Wastewater Tank #4202						X	
New Hot Oil Expansion Tank (H-4204)						X	
Existing Truck and Rail Loading of Renewable Diesel, Kerosene and SAF with Updated Throughputs						X	
New Blended SAF Loading						X	
Existing Rail Loading of Renewable Naphtha with Updated Throughput						X	

Source	PM_{FIL}	PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO
Existing PTU Wastewater Loading with Updated Throughput						X	
Existing PTU Blowdown Drum (D-4208) with Updated VOC Input						X	
New Heavy Fractions Loading						X	
New PTU Wastewater Treatment Plant						X	
New RFU Stripped Sour Water Recycling						X	

Definitions of Control Technologies

This section presents common technology descriptions that are used throughout this BACT analysis for the affected heaters.

For Carbon Monoxide

I. 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.

II. 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 carbon dioxide (CO_2). Thermal oxidation of a CO exhaust stream can be achieved by routing the stream to a flare, afterburner or regenerative or recuperative thermal oxidizer. The effectiveness of all thermal oxidation processes is influenced by residence time, mixing and temperature. Auxiliary fuel is typically required to achieve the temperature needed to ensure proper CO exhaust stream oxidation in a thermal oxidation device or process. 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.

III. Catalytic Oxidation

Catalytic oxidation makes use of catalysts, such as the precious metals platinum, palladium or rhodium, without the addition of any chemical reagents 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.

For Oxides of Nitrogen Control

IV. LNBs/ULNBs (Good Combustion Practices)

LNBs/ULNBs are available in a variety of configurations and burner types and they may incorporate one or more of the following concepts of good combustion practices: 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. Installation of LNBs/ULNBs constitute combustion modifications that would fall under "good combustion practices".

V. SCR

SCR is a post-combustion treatment technology that promotes the selective catalytic chemical reduction of NO_x (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 NO_x-containing combustion gases and the resulting mixture is passed through a catalyst bed, which catalyst serves to lower the activation energy of the NO_x reduction reactions. In the catalyst bed, the NO_x 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 NO_x occurs, resulting in the production of nitrogen and water from NO_x. 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.

VI. 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 NO_x-containing combustion gases and a portion of the NO_x 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 NO_x. Because a catalyst is not used with SNCR, the NO_x 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 NO_x reduction reactions will not effectively occur and much of the injected reagent will be emitted to the atmosphere along with the mostly uncontrolled NO_x emissions. At temperatures above

2,100°F, the desired NO_x reduction reactions will not effectively occur and the ammonia or urea reagent will begin to react with available oxygen to produce additional NO_x emissions.

VII. NSCR

NSCR is a post-combustion treatment technology that promotes the catalytic chemical reduction of NO_x (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 NO_x 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 NO_x 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.

For Particulate Matter Control

VIII. 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 grounded collection plates, which are periodically cleaned without re-entraining the PM into 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.

IX. 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.

X. Wet Scrubber

A 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 crossflow scrubbers, bubble plate scrubbers and tray scrubbers.

XI. 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.

For SO_2 Control

XII. 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.

XIII. 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 the following technologies [1]:

- Wet scrubbers,
- Semi-dry scrubbers, and

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[1] USEPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-034)

- Dry scrubbers [2], 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.

This section presents common technology descriptions that are used throughout this BACT analysis for Storage Tanks

For VOC Control

XIV. 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.

XV. Fixed Roof Storage Tank with Vapor Collection System and Control Device

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[2] Dry scrubbers also include dry sorbent injection (DSI)

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.

XVI. 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.

XVII. 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.

XVIII. 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.

XIX. Absorption (Wet Scrubber)

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 crossflow scrubbers, bubble plate scrubbers and tray scrubbers.

XX. 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 MRL 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.

XXI. 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.

XXII. Submerged Fill Loading

By incorporating submerged fill into the design of a loading operation, 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, the vapor vented from the storage tank contains less VOC, which means lower VOC emissions to the atmosphere.

New RFU Heater (H-4103)

The maximum air pollution control capability determinations made for the 80 million British thermal units per hour (MMBtu/hr) new Renewable Fuel Unit (RFU) Heater (H-4103) is summarized below in Table III-2. The analysis supporting the determinations are found below.

Table III-2
Summary of Proposed BACT Limits: New RFU Heater H-4103

Emissions Unit	Pollutant	Control Technology/Practice	Emissions Level
H-4103 Fired with Natural Gas and RFU Off-gas	CO	Good Combustion Practices	0.055 lb/MMBtu (HHV) (Average of three 1-hour runs)
	NO_X – Steady State Operations	ULNB (Good Combustion Practices)	0.035 lb/MMBtu (HHV) (30-day rolling average)
	NO_X – SSM Periods	ULNB (Good Combustion Practices)	3.08 lb/hr (SSM period average)
	PM (filt.)	Good Combustion Practices and use of low ash content fuels	0.0019 lb/MMBtu (HHV) (Average of three 1-hour runs)
	PM_{10} (filt. + cond.)		0.0075 lb/MMBtu (HHV) (Average of three 1-hour runs)
	$PM_{2.5}$ (filt. + cond.)		0.0075 lb/MMBtu (HHV) (Average of three 1 hour runs)
	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	0.0054 lb/MMBtu (HHV) (Average of three 1-hour runs)

Carbon Monoxide

H-4103 will combust a blend of pipeline quality natural gas and RFU off-gas. The heater will emit Carbon Monoxide (CO) due to the incomplete oxidation of hydrocarbons present in the natural gas and RFU off-gas. However, natural gas and RFU off-gas are both low-carbon fuels. This fuel characteristic will promote low levels of CO emissions from the heater.

Step 1: Identify Control Technologies

The following are available CO emission control technologies for H-4103.

- Good Combustion Practices;
- Thermal Oxidation; and
- Catalytic Oxidation.

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 carbon dioxide (CO_2). Thermal oxidation of a CO exhaust stream can be achieved by routing the stream to a flare, afterburner or regenerative or recuperative thermal oxidizer. The effectiveness of all thermal oxidation processes is influenced by residence time, mixing and temperature. Auxiliary fuel is typically required to achieve the temperature needed to ensure proper CO exhaust stream oxidation in a thermal oxidation device or process. 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, such as the precious metals platinum, palladium or rhodium, without the addition of any chemical reagents 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 Infeasible Options

The technical feasibility of the CO emission control technologies determined to be available for H-4103 is evaluated below.

Good Combustion Practices

Good combustion practices, including an oxygen monitoring system, 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 technically feasible for the control of CO emissions from the heater.

Catalytic Oxidation
Catalytic oxidation is technically feasible for the control of CO emissions from the heater.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The remaining available CO emission control technologies for H-4103 are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions:

- Thermal oxidation;
- Catalytic oxidation; and
- Good combustion practices.

Step 4: Evaluate Most Effective Control Options and Document Results
Below, MRL evaluated the cost effectiveness of the installation and operation of the CO emission control technologies that were determined to be technically feasible for H-4103.
Thermal Oxidation
The oxidation of CO to CO_2 is a time-dependent chemical reaction. For a thermal oxidation system to effectively reduce CO, the process requires a wide combustion chamber specifically designed for increased residence time to allow the chemical reactions to complete. This design will increase the cost of having a thermal oxidizer and require a large space to accommodate the device. Chamber residence time and temperature are directly linked. Shorter residence times (smaller chambers) require higher temperatures to achieve the same destruction rate, which increases fuel costs and can risk equipment damage.

Due to the very low concentration of CO in the heater's exhaust stream, the application of thermal oxidation to reduce CO emission rate would require either a large combustion chamber to provide sufficient reaction time or burning a considerable amount of fuel to achieve the elevated temperature necessary to promote the oxidation of the small amount of CO. Either option will increase the cost of having a thermal oxidizer for CO reduction.

Additionally, 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 NO_x emitted into the atmosphere.

MRL estimated a capital cost of approximately $2,500,000 – $3,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the heater's CO 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.

Research of emission control technology application data [i.e., Environmental Protection Agency's (EPA's) Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database] indicates that thermal oxidation has not been used to control CO emissions from a comparable heater.

Based on the above-described reasons, MRL concluded that it would not be cost effective to install a thermal oxidizer for H-4103. Therefore, MRL eliminated thermal oxidation from consideration as the maximum air pollution control capability for the heater's CO emissions.

Catalytic Oxidation

Like the existing heaters H-4101 and H-4102, the new heater H-4103's convection section will incorporate heat recovery to heat a process stream in a set of coils. Specifically, the convection section will incorporate a feed preheat coil. Based on MRL's operating records, the exhaust gas temperatures of the existing heaters H-4101 and H-4102 after the heat recovery operation vary between 450 Fahrenheit (°F) and 650°F, which is below the optimal temperature range of catalytic oxidation (650 – 1000°F). [Source: https://www.epa.gov/air-emissions-monitoring-knowledge-base/monitoring-control-technique-catalytic-oxidizer.To apply catalytic oxidation for the new heater H-4103, its convective heat recovery system will need to be specifically designed so that the catalyst is in the correct temperature window. Additionally, adding a catalytic bed will require installation of an induced draft (ID) fan, which will pull flue gases out of the combustion chamber, creating negative pressure within the system to ensure that flue gases are effectively directed through the catalytic oxidizer before being discharged. Moreover, the heat exchanger system will need to be designed with multiple, independently controlled sections or circuits to improve efficiency and operational flexibility.

MRL estimated a capital cost of approximately $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a catalytic oxidizer to collect and control the heater's CO emissions. Furthermore, annual operating costs (e.g., periodic catalytic replacements, electricity, maintenance labor and maintenance materials) required to operate and maintain the catalytic oxidizer would make it even less cost-effective.

Based on the above-described reasons, MRL concluded that it would not be cost effective to install a catalytic oxidizer for the new heater H-4103. Therefore, MRL eliminated catalytic oxidation from consideration as the maximum air pollution control capability for the heater's CO emissions.

Good Combustion Practices

The only remaining available CO emission control technology for the RFU Heater (H-4103) is good combustion practices, which will be an integral component of the design and operation of the heater.

Step 5: Select Maximum Air Pollution Control Capability

MRL determined that good combustion practices, including an oxygen monitoring system, represent the maximum air pollution control capability for CO emissions from Heater H-4103. Therefore,

MRL proposes the following maximum air pollutant control capability CO emission standard pursuant to ARM 17.8.752:

- CO emissions from the heater shall not exceed 0.055 pounds per MMBtu (lb/MMBtu), based on a 1- hour average as determined by three 1-hour runs.

Nitrogen Oxides

H-4103 will emit NO_x, primarily due to the thermal and prompt NO_x generation mechanisms because the heater's fuel will not contain appreciable amounts of organo-nitrogen compounds that result in fuel NO_x emissions. Thermal NO_x 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 NO_x 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 NO_x generation increases.

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

Step 1: Identify Control Technologies

The following are available NO_x emission control technologies for H-4103.

- LNBs/ULNBs (Good Combustion Practices);
- Selective Catalytic Reduction (SCR);
- Selective Non-catalytic Reduction (SNCR); and
- Non-Selective Catalytic Reduction (NSCR).

These technologies are generally described in the following sections.

LNBs/ULNBs (Good Combustion Practices)

LNBs/ULNBs are available in a variety of configurations and burner types and they may incorporate one or more of the following concepts of good combustion practices: 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. Installation of LNBs/ULNBs constitute combustion modifications that would fall under "good combustion practices".

SCR

SCR is a post-combustion treatment technology that promotes the selective catalytic chemical reduction of NO_x (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 NO_x-containing combustion gases and the resulting mixture is passed through a catalyst bed, which catalyst serves to lower the activation energy of the NO_x reduction reactions. In the catalyst bed, the

NO_x 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 NO_x occurs, resulting in the production of nitrogen and water from NO_x. 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.

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 NO_x-containing combustion gases and a portion of the NO_x 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 NO_x. Because a catalyst is not used with SNCR, the NO_x 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 NO_x reduction reactions will not effectively occur and much of the injected reagent will be emitted to the atmosphere along with the mostly uncontrolled NO_x emissions. At temperatures above 2,100°F, the desired NO_x reduction reactions will not effectively occur and the ammonia or urea reagent will begin to react with available oxygen to produce additional NO_x emissions.

NSCR

NSCR is a post-combustion treatment technology that promotes the catalytic chemical reduction of NO_x (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 NO_x 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 NO_x 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

The technical feasibility of the NO_x emission control technologies determined to be available for H-4103 is evaluated below.

LNBs/ULNBs (Good Combustion Practices)

The heater will be equipped with ULNBs, which implement good combustion practices, including minimizing excess air, ensuring proper fuel and air mixing, maintaining low flame temperatures, and controlling residence times, etc. This option is technically feasible.

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 NO_x emission reduction, especially in turndown modes of operation. However, MRL conservatively estimated SNCR is technically feasible to control the heater's NO_x emissions.

NSCR

NSCR technology is not technically feasible for the control of NO_x emissions from the heater because it will not operate at the 0.5% or less excess oxygen concentration necessary to ensure NO_x reduction with NSCR. Instead, the heater will operate with an excess oxygen concentration of approximately 2 to 3%. This amount of excess oxygen will promote 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 NO_x emissions from a comparable heater. These factors indicate that it is not technically feasible to use NSCR to control the heater's NO_x emissions.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The remaining available NO_x emission control technologies for H-4103 are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions.

- SCR – Typical SCR control efficiencies are highly dependent on flue gas temperatures as well as inlet NO_x concentrations, and can range from 62 – 92%[3];
- SNCR – Typical SNCR control efficiencies range from 25 – 60% for urea-based systems and 61 – 65% for ammonia-based systems[4]; and
- ULNBs – H-4103 will be equipped with ULNBs, which reflect good combustion practices, as its base design. For natural gas-fired boilers/heaters, ULNBs can achieve approximately 30-50% NO_x control (again, depending on the inlet NO_x concentrations).

Step 4: Evaluate Most Effective Control Options and Document Results

Below, MRL evaluated the cost effectiveness of the installation and operation of the NO_x emission control technologies that were determined to be technically feasible for H-4103 but not already included in its base design.

SCR

As indicated in the application materials, MRL estimated that the installation and operation of an SCR system on the heater would result in a cost effectiveness equal to approximately $40,651 per ton of NO_x emission reduction, which is not cost effective. The cost for the installation and

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[3] https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

[4] https://www.epa.gov/sites/default/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf

operation of an SCR system on the heater was estimated using the SCR cost estimating spreadsheet that EPA developed and published in June of 2019. 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 greenhouse gas (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 NO_x emissions.

SNCR

As indicated in the application materials, MRL estimated that the installation and operation of an SNCR system on the heater would result in a cost effectiveness equal to approximately $26,253 per ton of NO_x emission reduction, which is not cost effective. The cost for the installation and operation of an SNCR system on the heater was estimated using the SNCR cost estimating spreadsheet that EPA developed and published in March of 2021. 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 likely result in increased GHG and non-GHG emission rates at one or more power generating stations, 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 collateral emissions of GHG and non-GHG pollutants. For these reasons, MRL eliminated an SNCR system from consideration as the maximum air pollution control capability for the heater's NO_x emissions.

Step 5: Select Maximum Air Pollution Control Capability

MRL determined that ULNBs represent the maximum air pollution control capability for the NO_x emissions from H-4103. The heater will be equipped with ULNBs and MRL will comply with the following emission limitation to reflect the performance of the maximum air pollution control capability for this unit:

- NO_x emissions from the H-4103 shall not exceed 0.035 lb/MMBtu (HHV), based on a 30-day rolling average during steady state operations.

BACT for NOx during Startup, Shutdown and Maintenance (SSM) Periods (H-4103)

Step 1: Identify all Control Options

Available control options for steady state operation of this heater considered:

- LNBS/ULBNs (Good Combustion Practices); See linked description at Definition Section IV.
- SCR; See linked description at Definition Section V
- SNCR; See linked description a Definition Section VI.
- NSCR. See linked description at Definition Section VII

In addition, MRL also evaluated potential ways to minimize the startup period, maintain optimal oxygen content and reduce NOx emissions while maintaining and balancing heater startup operating safety in accordance with the startup procedures. However, a cold startup process can normally take up to 24 hours and maintaining NOx emissions in compliance with the short-term lb/MMBtu-based emission limits during the entire startup period can be challenging. To that end, MRL proposes the above-mentioned best management practices that would minimize emissions by reducing the duration of startup. Minimizing the duration of the startup combined with a higher lb/MMBtu limit to reflect steady state controls are not fully functional during these periods.

Step 2: Eliminate Technically Infeasible Options

During SSM periods, none of the add-on NO_x control devices are up to temperature to offer the level of NO_x control required for meeting the proposed lb/MMBtu permit limit. While H-4103 can comply with the proposed 0.035 lb/MMBtu steady state BACT limit (as a 30-day rolling average) during steady state operations, the unit's emission rate during SSM periods may exceed 0.035 lb/MMBtu during those events. However, the heat input to the heater during SSM periods is expected to be low such that even at the elevated lb/MMBtu, the maximum short-term emissions [pounds per hour (lb/hr)] are not exceeded. MRL follows the prescribed startup procedure to start each heater, and the same procedures will be applied to this unit. Startup occurs at an acceptable maximum firing rate while maintaining safety and compliance with the equipment maximum pressure and temperature operating curve.

Therefore, SCR, SNCR and NSCR are each technically infeasible during these transient periods of startup, shutdown and malfunction.

To a limited degree good combustion practices and equipping the heater with ULBNs are still viable during transient events, and the controls are already in place related to steady state operation proposed BACT.

Procedures associated with the transient periods, and an appropriate higher lb/MMBTU limit, particularly with startup, remain a viable control option for allowing efficient startup periods.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Both good combustion practices and following developed procedures for transient operation, particularly startup which requires longer warm-up times to avoid metal fatigue and other heat-related stresses, are available.

Step 4: Evaluate Most Effective -Control Options and Document Results
Good combustion practices and following developed procedures for minimizing transient durations are both effective. Combining good combustion practices and procedures, MRL has determined an expected lb/hr limit that could be achieved. The lb/hr-based SSM NOx emission limit is determined based on the above-described stead-state BACT limit of 0.035 lb/MMBtu and the heater's maximum firing rate 80 MMBtu/hr, with an additional 10% safety factor applied. The resulting limit would provide a 3.08 lb/hr limit calculated as an overall average of the transient period of an SSM event.

Step 5: Select BACT
MRL proposed Good Combustion Practices, use of developed procedures limiting transient period duration, and a BACT limit of 3.08 lb/hr over the transient period of each SSM event.

SSM periods are defined in Section IV of the permit and subject to ARM 17.8.749.

Particulate Matter PM/PM10/PM2.5
H-4103 will emit particular matter (PM), PM_{10} and $PM_{2.5}$ comprised of filterable and condensable portions. A gaseous fuel combustion device can emit condensable PM_{10} and $PM_{2.5}$ 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 RFU off-gas, which are primarily comprised of hydrogen and relatively low molecular weight hydrocarbons. Therefore, PM emissions from the incomplete combustion of high molecular weight hydrocarbons are not expected to occur. Additionally, the proposed fuels contain low levels of sulfur, further minimizing the generation of PM_{10} and $PM_{2.5}$ when they are combusted.

Step 1: Identify Control Technologies
The following are available PM emission control technologies for the RFU Heater (H-4103).

- Good Combustion Practices;
- Electrostatic Precipitator (ESP);
- Filter;
- Wet Scrubber; and
- Cyclone.

These technologies are generally described below.

Good Combustion Practices
Please see Definition I herein for a discussion of this technology.

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 grounded collection plates, which are periodically cleaned without re-entraining the PM into 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

A 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 crossflow 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
The technical feasibility of the PM emission control technologies determined to be available for the RFU Heater (H-4103) 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.

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 required for effective performance of the ESP. 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.

Fabric Filter / Baghouse

Baghouses/fabric filters are not used on natural gas-fired combustion units due to the inherently low filterable PM content of natural gas. Uncontrolled PM emissions from natural gas combustion are already on the order of ~0.001 to 0.003 lb/MMBtu, which is comparable to or below typical fabric filter outlet concentrations. Therefore, the installation of a baghouse would provide negligible emission reduction at disproportionate capital and operating cost.

Secondly, conventional filter bags have temperature limits, typically ranging from 275°F (e.g., standard polyester bags) to 500°F (e.g., fiberglass, Nomex, Teflon). Flue gas from fuel gas combustion of the heater (expected to be 450°F – 650°F) could melt or damage the filter material.

Thirdly, fuel gas combustion produces a high volume of moisture in the flue gas. When the flue gas drops below its dew point, moisture can condense on the filter bags, which will cause the bags to become clogged as the fine condensable PM sticks to the wet fabric and thus will not lower the condensable PM emissions by any appreciable amount. Additionally, condensation can also cause corrosion to the baghouse's metal components, leading to material degradation and equipment failure.

Furthermore, research of emission control technology application data sets indicates a filter has not been used to control PM emissions from a comparable gas-fired 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 by Control Effectiveness
The only remaining available PM, PM_{10} and $PM_{2.5}$ emission control technology for the RFU Heater (H-4103) is good combustion practices.

Step 4: Evaluate Most Effective Control Options and Document Results
The only remaining available PM, PM_{10} and $PM_{2.5}$ emission control technology for H-4103) is good combustion practices.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that good combustion practices represent the maximum air pollution control capability for the PM, PM_{10} and $PM_{2.5}$ emissions from H-4103. Therefore, MRL will control PM, PM_{10} and $PM_{2.5}$ emissions from the heater by using good combustion practices and comply with the following emission limitations to reflect the performance of the maximum air pollution control capability for this unit:

- PM (filterable) emissions from the heater shall not exceed 0.0019 lb/MMBtu (HHV), based on the average of three 1-hour runs;
- PM_{10} emissions from the heater shall not exceed 0.0075 lb/MMBtu (HHV), based on the average of three 1-hour runs; and
- $PM_{2.5}$ emissions from the heater shall not exceed 0.0075 lb/MMBtu (HHV)based on the average of three 1-hour runs.

Sulfur Dioxide
The new H-4103 will combust pipeline quality natural gas and RFU off-gas. The natural gas will contain a negligible amount of hydrogen sulfide (H_2S). Additionally, the RFU off-gas will be treated to minimize its H_2S content. Therefore, the heater will emit only a small amount of sulfur dioxide (SO_2).

The heater will not be an affected facility under NSPS Subpart Ja as MRL is not a "petroleum refinery".

The heater will be subject to the following state 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 cubic feet (ft^3) of gaseous fuel, calculated as H_2S at standard conditions [or approximately 808 parts per million by volume (ppmv) H_2S].

Step 1: Identify Control Technologies
The following are available SO_2 emission control technologies for the new RFU Heater (H-4103).

- Low Sulfur Fuel
- Flue Gas Desulfurization

These technologies are generally described in the following subsections.

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 the following technologies [5]:

- Wet scrubbers,
- Semi-dry scrubbers, and
- Dry scrubbers [6], 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.

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5 USEPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-034)

6 Dry scrubbers also include dry sorbent injection (DSI)

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

The technical feasibility of the SO_2 emission control technologies determined to be available for the H-4103 is evaluated below.

Low Sulfur Fuel

Use of low sulfur fuel is technically feasible for the heater.

Flue Gas Desulfurization

As noted previously, flue gas desulfurization consists of three main types of scrubbers – wet, dry and semi-dry. 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. Flue gas desulfurization systems rely on efficient mass transfer of SO_2 from the gas stream into a liquid or solid absorbent. Due to the very low concentration of SO_2 in the exhaust gas stream, the "driving force" for this mass transfer would be extremely inefficient, which makes it difficult for the absorbent to capture the sulfur molecules in flue gas effectively.

Additionally, with low inlet SO_2 concentrations in flue gas, it is very challenging to control the system's chemistry and maintain the ideal pH for the scrubbing liquid, which further reduces removal efficiency.

Furthermore, 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.

Lastly, research of emission control technology application data sets indicate that wet, semi-dry and dry scrubbers have not been used to control SO_2 emissions from a comparable natural gas-fired 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 H-4103 is low sulfur fuel.

Step 4: Evaluate Most Effective Control Options and Document Results

The only remaining available SO_2 emission control technology for H-4103 is low sulfur fuel.

Step 5: Select Maximum Air Pollution Control Capability

MRL determined that combusting low sulfur gaseous fuel represents the maximum air pollution control capability for the SO_2 emissions from H-4103. Specifically, MRL will control SO_2 emissions from H-4103 by combusting gaseous fuel containing no more than 30 ppmv H_2S, with an annual average of no more than 10 ppmv H_2S.

Volatile Organic Compounds

H-4103 will emit volatile organic compounds (VOCs) 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.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for H-4103.

- Good Combustion Practices;
- Thermal Oxidation; and
- Catalytic Oxidation.

Below, these technologies are generally described.

Good Combustion Practices
Please see the Definition Section I herein for a discussion of this technology.

Thermal Oxidation
Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation
Please see the Definition Section III 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 H-4103 is evaluated below.

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 technically feasible for the control of VOC emissions from the heater.

Catalytic Oxidation

Catalytic oxidation is technically feasible for the control of VOC emissions from the heater, although due to the considerably low concentration of VOC 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 by Control Effectiveness
The remaining available VOC emission control technologies for H-4103 are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions:

- Thermal oxidation;

- Catalytic oxidation; and
- Good combustion practices.

Step 4: Evaluate Most Effective Control Options and Document Results
Below, MRL evaluated the cost effectiveness of the installation and operation of the VOC emission control technologies that were determined to be technically feasible for H-4103.

Thermal Oxidation

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 NO_x 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.

Lastly, MRL estimated a capital cost of approximately $2,500,000 – $3,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the heater's VOC emissions of 1.89 tons per year (tpy). 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.

Based on the above-described reasons, MRL concluded that it would not be cost effective to install a thermal oxidizer for the new heater H-4103. Therefore, MRL eliminated thermal oxidation from consideration as the maximum air pollution control capability for the heater's VOC emissions.

Catalytic Oxidation

Like the existing heaters H-4101 and H-4102, the new heater H-4103's convection section will incorporate a feed preheat coil. Based on MRL's operating records, the exhaust gas temperatures of the existing heaters H-4101 and H-4102 after the heat recovery operation vary between 450 °F and 650°F, which is below the optimal temperature range of catalytic oxidation (650 – 1000°F). To apply catalytic oxidation for the new heater H-4103, its convective heat recovery system will need to be specifically designed so that the catalyst is in the correct temperature window. Adding a catalytic bed will require installation of an ID fan, and the heat exchanger system will need to be designed with multiple, independently controlled sections or circuits to improve efficiency and operational flexibility.

MRL estimated a capital cost of approximately $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a catalytic oxidizer to collect and control the heater's VOC emissions of 1.89 tpy. Furthermore, annual operating costs (e.g., periodic catalytic replacements, electricity, maintenance labor and maintenance materials) required to operate and maintain the catalytic oxidizer would make it even less cost-effective.

Based on the above description, MRL concluded that it would not be cost effective to install a catalytic oxidizer for the new heater H-4103. Therefore, MRL eliminated catalytic oxidation from consideration as the maximum air pollution control capability for the heater's VOC emissions

Good Combustion Practices

The only remaining available VOC emission control technology for H-4103 is good combustion practices, which will be an integral component of the design and operation of the heater.

Step 5: Select Maximum Air Pollution Control Capability

MRL determined that good combustion practices represent the maximum air pollution control capability for the VOC emissions from H-4103. Therefore, MRL will control VOC emissions from the heater by using good combustion practices and comply with the following emission limitation to reflect the performance of the maximum air pollution control capability for this unit:

- VOC emissions from the heater shall not exceed 0.0054 lb/MMBtu (HHV), based on a 3-hr average.

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.

Additional Applicability:

Separate and distinct from the BACT analysis, the heater will be subject to the following work practice standards in 40 CFR, Part 63, Subpart DDDDD – *National Emission Standards for Hazardous Air Pollutants (NESHAP) for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters*: These requirements are applicable under ARM 17.8.749. These applicable requirements are included here as they further support federal requirements for maintaining proper equipment operation.

- 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.
- 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 the nitrogen oxides (NO_x) 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.

The heater will not be subject to an NSPS or NESHAP emission standard. MRL proposes the following opacity and maximum air pollution control capability for PM, PM_{10} and $PM_{2.5}$:

- 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.

Hydrogen Plant #5 Reformer Heater (H-5801)

The maximum air pollution control capability determinations made for the new Hydrogen Plant #5 Reformer Heater (H-5801) – 469 MMBtu/hr pursuant to ARM 17.8.752 is summarized below in Table III-3. The analysis supporting the determinations are found below

Table III-3
Summary of Proposed BACT Limits: Hydrogen Plant #5 Heater H-5801

Emissions Unit	Pollutant	Control Technology/Practice	Emissions Level
H-5801 Fired with PSA Off-gas and RFU Off-gas	CO	Good Combustion Practices	0.03 lb/MMBtu (HHV) (Average of three 1-hour runs)
	NO_X – Steady State Operations	ULNB (Good Combustion Practices) and SCR	0.004 lb/MMBtu (HHV) (30-day rolling average)
	NO_X – SSM & SCR Warm-up Periods	ULNB (Good Combustion Practices)	20.64 lb/hr (HHV) (SSM period average)
	PM (filt.)	Good Combustion Practices and use of low ash content fuels	0.0019 lb/MMBtu (HHV) (Average of three 1-hour runs)
	PM_{10} (filt. + cond.)		0.0075 lb/MMBtu (HHV) (Average of three 1-hour runs)
	$PM_{2.5}$ (filt. + cond.)		0.0075 lb/MMBtu (HHV) (Average of three 1-hour runs)
	SO_2	Low Sulfur Gaseous Fuel	Fuel gas containing ≤30 ppmv H_2S maximum and ≤10 ppmv H_2S on an annual average basis
	VOC	Good Combustion Practices	0.0054 lb/MMBtu (HHV) (Average of three 1-hour runs)

Carbon Monoxide

The Hydrogen Plant #5 Reformer Heater (H-5801) will combust PSA off-gas and RFU off-gas. The PSA off-gas will be mainly comprised of methane (CH_4), hydrogen, CO, CO_2, water and nitrogen and the primary constituents of the RFU off-gas will typically be CH_4, ethane, propane, butanes, pentanes and hydrogen. The heater will emit CO due to the incomplete oxidation of hydrocarbons present in its gaseous fuels. However, the PSA off-gas and RFU off-gas will be low-carbon fuels. 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 the heater's combustion process, as needed. This system will greatly assist in minimizing the heater's CO emissions by providing the site with the capability to maintain good combustion practices at the heater.

Step 1: Identify Control Technologies

The following are available CO emission control technologies for H-5801.

- Good Combustion Practices;
- Thermal Oxidation; and
- Catalytic Oxidation.

Below these technologies are generally described.

Good Combustion Practices

Please see the Definition Section I herein for a discussion of this technology.

Thermal Oxidation

Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation

Please see the Definition Section III herein for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the CO emission control technologies determined to be available for H-5801 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 technically feasible for the control of CO emissions from the heater.

Catalytic Oxidation

Catalytic oxidation is not technically feasible for the control of CO emissions from reformer heater fuel combustion at a hydrogen plant primarily because of catalyst poisoning by sulfur compounds and operational temperature constraints.

The fuel gas for reformer heaters typically contains sulfur compounds, even after desulfurization. These sulfur species poison the platinum-group metal (PGM) catalysts used in catalytic oxidation by binding strongly to the active sites on the catalyst surface, deactivating them and significantly reducing the catalyst's effectiveness and lifespan. This makes it difficult to achieve and maintain the necessary CO oxidation rates.

Additionally, the firebox of a hydrogen plant's steam methane reformer operates at very high temperatures (expected to be greater than 1,800 °F). Standard catalytic oxidizers are designed to operate at much lower temperatures, typically between 650 – 1000 °F. The extreme temperatures would cause thermal degradation of the catalyst material itself and a loss of active surface area. This would dramatically shorten the catalyst's useful life and necessitate frequent, costly replacements.

Moreover, while catalysts allow oxidation to occur at lower temperatures, trying to force a catalytic system to operate in a high-temperature environment would require significant and often impractical energy input.

Based on the above-described factors, catalytic oxidation is not technically feasible for controlling CO emissions from H-5801.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The remaining available CO emission control technologies for H-5801 are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions:

- Thermal oxidation; and
- Good combustion practices.

Step 4: Evaluate Most Effective Control Options and Document Results
Below, MRL evaluated the cost effectiveness of the installation and operation of the CO emission control technologies that were determined to be technically feasible H-5801.

Thermal Oxidation
The oxidation of CO to CO_2 is a time-dependent chemical reaction. For a thermal oxidation system to effectively reduce CO, the process requires a wide combustion chamber specifically designed for increased residence time to allow the chemical reactions to complete. This design will increase the cost and require a large space to accommodate the device. Chamber residence time and temperature are directly linked. Shorter residence times (smaller chambers) require higher temperatures to achieve the same destruction rate, which increases fuel costs and can risk equipment damage.

Due to the very low concentration of CO in the heater's exhaust stream, the application of thermal oxidation to reduce the heater's CO emission rate would require either a large combustion chamber to provide sufficient reaction time or burning a considerable amount of fuel to achieve the elevated temperature necessary to promote the oxidation of the small amount of CO. Either option will increase the cost of having a thermal oxidizer for CO reduction.

Additionally, 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 NO_x and CO_2, emitted into the atmosphere. Furthermore, research of emission control technology application data sets indicates thermal oxidation has not been used to control CO emissions from a comparable heater.

MRL estimated a capital cost of approximately \$2,500,000 – \$3,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the heater's CO 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.

Based on the above-described factors, MRL concluded that it would not be cost effective to install a thermal oxidizer for H-5801. Therefore, MRL eliminated thermal oxidation from consideration as the maximum air pollution control capability for the heater's CO emissions.

Good Combustion Practices

The only remaining available CO emission control technology for H-5801 is good combustion practices, which will be an integral component of the design and operation of the heater.

Step 5: Select Maximum Air Pollution Control Capability

MRL determined that good combustion practices represent the maximum air pollution control capability for CO emissions from H-5801. Therefore, MRL will control CO emissions from the heater by using good combustion practices and complying with the following emission limitation:

- CO emissions from H-5801 shall not exceed 0.03 lb/MMBtu (HHV), based on 1-hr average as determined from three 1-hour runs.

Nitrogen Oxides

H-5801 will emit NO_x, primarily due to the thermal and prompt NO_x generation mechanisms because the heater's PSA off-gas and RFU off-gas fuels will not contain appreciable amounts of organo-nitrogen compounds that result in fuel NO_x emissions. Thermal NO_x 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 NO_x generation is affected by the following three factors: oxygen concentration, peak flame temperature and the duration at peak flame temperature. As these three factors increase in value, the rate of thermal NO_x generation increases.

Prompt NO_x 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 NO_x may represent a meaningful portion of the NO_x emissions resulting from LNBs and ULNBs.

Step 1: Identify Control Technologies

The following are available NO_x emission control technologies for H-5801.

- LNBs/ULNBs (Good Combustion Practices);
- SCR;
- SNCR; and
- NSCR.

These technologies are generally described below.

LNBs/ULNBs (Good Combustion Practices)
Please see Definition Section IV herein for a discussion of this technology.

SCR
Please see Definition Section V herein for a discussion of this technology.

SNCR
Please see Definition Section VI herein for a discussion of this technology.

NSCR
Please see Definition Section VII herein for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the NO_x emission control technologies determined to be available for H-5801 is evaluated below.

LNBs/ULNBs (Good Combustion Practices)
This option is technically feasible 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 NO_x emission reduction, especially in turndown modes of operation. In consideration of the optimal SNCR temperature profiles, reagent injection points would likely be evaluated for installation in the firebox of the heater. In fact, the designer of the heater, TechnipFMC, has evaluated the application of SNCR on its reformer heaters and determined that the SNCR reagent would need to be injected into the heater's firebox to achieve the residence time necessary for the reagent to react with NO_x. However, the very high temperatures in the firebox region (expected to be greater than 1,800 °F) that would provide an acceptable residence time would also lead to the oxidation of reagent and the generation of additional NO_x. Therefore, it is not technically feasible to use SNCR to control the heater's NO_x emissions.

NSCR

NSCR technology is not technically feasible for the control of NO_x emissions from the heater because it will not operate at the 0.5% or less excess oxygen concentration necessary to ensure NO_x reduction with NSCR. Instead, the heater will operate with an excess oxygen concentration between approximately 2 and 2.5%. This range of excess oxygen concentrations will promote 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) that may occur at the plant. Furthermore, research of emission control technology application data sets indicated NSCR has not been used to control NO_x emissions from a comparable heater. These factors indicate it is not technically feasible to use NSCR to control the heater's NO_x emissions.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The remaining available NO_x emission control technologies for H-5801 are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions.

- SCR; and
- ULNB.

Step 4: Evaluate Most Effective Control Options and Document Results
MRL has elected to equip the H-5801 with ULNBs and install a SCR for further reduction of NOx emissions, the most efficient control technology for this source and therefore does not need to conduct an economic impact analysis of these technologies.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that ULNBs with SCR control represent the maximum air pollution control capability for the NO_x emissions from H-5801. Therefore, MRL will control NO_x emissions from the heater by equipping it with ULNBs and a SCR to comply with the following emission limitation:

- NO_x emissions from H-5801, during steady state operations, shall not exceed 0.004 lb/MMBtu (HHV), based on a 30-day rolling average.

BACT for NOx during SSM and SCR Warm-up Periods
Step 1: Identify all Control Options
Available control options for steady state operation of this heater considered:

- LNBS/ULBNs (Good Combustion Practices);
- SCR;
- SNCR; and
- NSCR.

Each of these technologies are described beginning in the Definition Section IV.

In addition, MRL also evaluated potential ways to minimize the startup period, maintain optimal oxygen content and reduce NO_x emissions while maintaining and balancing heater startup operating safety in accordance with the startup procedures. However, a cold startup process can normally take up to 24 hours and maintaining NO_x emissions in compliance with the short-term lb/MMBtu-based emission limits during the entire startup period can be challenging. To that end, MRL proposes the above-mentioned best management practices that would minimize emissions by reducing the duration of startup. Minimizing the duration of the startup combined with a higher lb/MMBtu limit to reflect steady state controls are not fully functional during these periods.

Step 2: Eliminate Technically Infeasible Options
During SSM periods, none of the add-on NO_x control devices are up to temperature to offer the level of NO_x control required for meeting the proposed lb/MMBtu permit limit. While the heater H-5801 can comply with the proposed 0.004 lb/MMBtu steady state BACT limit (as a 30-day rolling average) during steady state operations, the unit's emission rate during SSM periods and SCR warm-up periods may exceed 0.004 lb/MMBtu during those events. However, the heat input to the heater during SSM periods is expected to be low such that even at the elevated lb/MMBtu, the maximum short-term emissions (lb/hr) are not exceeded. MRL follows the prescribed startup procedure to start each heater, and the same procedures will be applied to this unit. Startup occurs at an acceptable maximum firing rate while maintaining safety and compliance with the equipment maximum pressure and temperature operating curve.

Therefore, SCR, SNCR and NSCR are each technically infeasible during these transient periods of startup, shutdown and malfunction.

To a limited degree good combustion practices and equipping the heater with ULBNs are still viable during transient events, and the controls are already in place related to steady state operation proposed BACT.

Procedures associated with the transient periods, and an appropriate higher lb/MMBTU limit, particularly with startup, remain a viable control option for allowing efficient startup periods.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
Both good combustion practices and following developed procedures for transient operation, particularly startup which requires longer warm-up times to avoid metal fatigue and other heat-related stresses, are available.

Step 4: Evaluate Most Effective -Control Options and Document Results
Good combustion practices and following developed procedures for minimizing transient durations are both effective. Combining good combustion practices and procedures, MRL has determined an expected lb/hr limit that could be achieved. The lb/hr-based SSM NO_x emission limit is determined based on the pre-SCR-controlled NOx emission rate of 0.04 lb/MMBtu and the heater's maximum firing rate 469 MMBtu/hr, with an additional 10% safety factor applied. The resulting limit would provide a 20.64 lb/hr limit calculated as an overall average over the transient period of an SSM event.

Step 5: Select BACT
MRL proposed Good Combustion Practices, use of developed procedures limiting transient period duration, and a NO_x emission limit of 20.64 lb/hr (over the transient period of each SSM event).

SSM periods are defined in Section IV of the permit and subject to ARM 17.8.749.

PM/PM10/PM2.5

H-5801 will emit PM, PM_{10} and $PM_{2.5}$ comprised of filterable and condensable portions. The heater will combust PSA off-gas and RFU off-gas, which contain relatively low levels of high molecular weight hydrocarbons. Therefore, elevated PM, 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 gaseous fuels will pass through desulfurization, which is an integral process in hydrogen production to reduce their H_2S concentrations to low levels, further minimizing the generation of PM_{10} and $PM_{2.5}$ when they are combusted.

Step 1: Identify Control Technologies
The following are available PM, PM_{10} and $PM_{2.5}$ emission control technologies for H-5801.

- Good Combustion Practices;
- ESP;
- Filter;
- Wet Scrubber; and
- Cyclone.

These technologies are generally described below.

Good Combustion Practices
Please see the Definition Section I herein for a discussion of this technology.

ESP
Please see the Definition Section VIII herein for a discussion of this technology.

Filter
Please see the Definition Section IX herein for a discussion of this technology.

Wet Scrubber
Please see the Definition Section X herein for a discussion of this technology.

Cyclone
Please see the Definition Section XI herein for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the PM, PM_{10} and $PM_{2.5}$ emission control technologies determined to be available for H-5801 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.

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 emission control technology application data sets 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.

Fabric Filter / Baghouse

Baghouses/fabric filters are not used on natural gas-fired combustion units due to the inherently low filterable PM content of natural gas. Uncontrolled PM emissions from natural gas combustion are already on the order of ~0.001 to 0.003 lb/MMBtu, which is comparable to or below typical fabric filter outlet concentrations. Therefore, the installation of a baghouse would provide negligible emission reduction at disproportionate capital and operating cost.

Secondly, conventional filter bags have temperature limits, typically ranging from 275°F (e.g., standard polyester bags) to 500°F (e.g., fiberglass, Nomex, Teflon). Flue gas from fuel gas combustion of the reformer heater could melt or damage the filter material.

Thirdly, fuel gas combustion produces a high volume of moisture in the flue gas. When the flue gas drops below its dew point, moisture can condense on the filter bags, which will cause the bags to become clogged as the fine condensable PM sticks to the wet fabric and thus will not lower the condensable PM emissions by any appreciable amount. Additionally, condensation can also cause corrosion to the baghouse's metal components, leading to material degradation and equipment failure.

Furthermore, research of emission control technology application data sets 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 emission control technology application data sets 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 emission control technology application data sets 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 by Control Effectiveness

The only remaining available PM, PM_{10} and $PM_{2.5}$ emission control technology for H-5801 is good combustion practices.

Step 4: Evaluate Most Effective Control Options and Document Results

The only remaining available PM, PM_{10} and $PM_{2.5}$ emission control technology for H-5801 is good combustion practices.

Step 5: Select Maximum Air Pollution Control Capability

MRL determined that good combustion practices represent the maximum air pollution control capability for the PM, PM_{10} and $PM_{2.5}$ emissions from H-5801. Therefore, MRL will control PM, PM_{10} and $PM_{2.5}$ emissions from the heater by using good combustion practices and comply with the following emission limitations to reflect the performance of the maximum air pollution control capability for this unit:

- PM (filterable) emissions from the heater shall not exceed 0.0019 lb/MMBtu (HHV), based on the average of three 1-hour runs;

- PM_{10} emissions from the heater shall not exceed 0.0075 lb/MMBtu (HHV), based on the average of three 1-hour runs; and
- $PM_{2.5}$ emissions from the heater shall not exceed 0.0075 lb/MMBtu (HHV) based on the average of three 1-hour runs.

Sulfur Dioxide

H-5801 will use RFU purge gas and RFU off-gas as feedstock gas options (in addition to natural gas) to produce hydrogen. RFU purge gas is a stream of gas intentionally removed from the RFU system to control concentration of non-reactive compounds and contains a high concentration of unreacted hydrogen that was not consumed in the hydrotreating reaction, plus any inert gases that have built up in the system. RFU off-gas is generated as a byproduct of chemical reactions during hydrotreating and is primarily a mixture of hydrocarbons (propane, methane) and unreacted hydrogen. Both gases will contain H_2S and will pass through a desulfurization process first to remove sulfur compounds before the main hydrogen production steps. The removal is critical because sulfur compounds can poison the hydrogen production catalysts by binding strongly to the surface of the catalysts and therefore blocking the active sites required for the reforming reaction. This will reduce catalyst efficiency and necessitate more frequent and costly catalyst replacement. Integrating a desulfurization step upfront will protect the catalysts, ensure long-term operational stability, and reduce unscheduled downtime. As such, the desulfurization step is an integral process in a hydrogen plant and it should not be considered an emission control technology, although this step helps to reduce the H_2S content in the gases and minimize SO_2 emissions in the subsequent fuel combustion process.

After desulfurization, the desulfurized gases will be sent to the hydrogen plant reformer and the water-gas shift (WGS) reactor to convert hydrocarbons and CO into hydrogen. The hydrogen-rich stream from the reformers will then be sent to a Pressure Swing Adsorption (PSA) unit for final purification to separate hydrogen from impurities like CO_2, methane, CO, and residual water vapor.

The separated impurities from the PSA unit (referred to as the PSA off-gas) will be used as fuel gas for the Hydrogen Plant #5 reformer heater H-5801. Due to the upfront desulfurization, the fuel gas combustion in the heater will emit only a small amount of SO_2 emissions.

H-5801 will be subject to the following MTDEQ 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 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 H-5801.

- Low Sulfur Fuel; and
- Flue Gas Desulfurization.

Below these technologies are generally described.

Low Sulfur Fuel

Please see the Definition Section XII herein for a discussion of this technology.

Flue Gas Desulfurization

Please see the Definition Section XIII herein for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the SO_2 emission control technologies determined to be available for H-5801 is evaluated below.

Low Sulfur Fuel
Low sulfur fuel is technically feasible for the heater.

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.

H-5801 will emit SO_2 at concentrations less than 15 ppmv, which are below the concentrations oftentimes seen in a wet scrubber's exhaust stream. Flue gas desulfurization systems rely on efficient mass transfer of SO_2 from the gas stream into a liquid or solid absorbent. When the concentration of SO_2 is very low, the "driving force" for this mass transfer is extremely inefficient, which makes it difficult for the absorbent to capture the remaining sulfur molecules effectively.

Additionally, with low inlet SO_2 concentrations in flue gas, it is very challenging to control the system's chemistry and maintain the ideal pH for the scrubbing liquid, which further reduces removal efficiency.

Furthermore, 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.

Lastly, research of emission control technology application data sets indicated 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 H-5801 is low sulfur fuel.

Step 4: Evaluate Most Effective Control Options and Document Results
The only remaining available SO_2 emission control technology for H-5801 is low sulfur fuel.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that combusting low sulfur gaseous fuel represents the maximum air pollution control capability for the SO_2 emissions from H-5801. Specifically, MRL shall control SO_2 emissions from the heater by combusting PSA off-gas and RFU off-gas containing no more than 30 ppmv H_2S with an annual average of no more than 10 ppmv H_2S.

Volatile Organic Compounds
H-5801 will emit VOC due to the incomplete oxidation of hydrocarbons present in its gaseous fuels. However, the low molecular weight characteristic of the hydrocarbons in the PSA off-gas and RFU off-gas will promote low levels of VOC emissions from the heater.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for H-5801.

- Good Combustion Practices;
- Thermal Oxidation; and
- Catalytic Oxidation.

Below these technologies are generally described.

Good Combustion Practices
Please see the Definition I herein for a discussion of this technology.

Thermal Oxidation
Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation
Please see the Definition III 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 H-5801 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 technically feasible for the control of VOC emissions from the heater.

Catalytic Oxidation
As described catalytic oxidation is not technically feasible for the control of VOC emissions from the heater due to catalyst poisoning by sulfur compounds and operational temperature constraints.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The remaining available VOC emission control technologies forH-5801 are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions:

- Thermal oxidation; and
- Good combustion practices

Step 4: Evaluate Most Effective Control Options and Document Results
Below, MRL evaluated the cost effectiveness of the installation and operation of the VOC emission control technologies that were determined to be technically feasible for H-5801.

Thermal Oxidation
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 NO_x and CO_2, emitted into the atmosphere. Furthermore, research of emission control technology application data sets indicated thermal oxidation has not been used to control VOC emissions from a comparable heater.

Lastly, MRL estimated a capital cost of approximately $2,500,000 – $3,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the heater'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.

Based on the above-described reasons, MRL concluded that it would not be cost effective to install a thermal oxidizer for H-5801. Therefore, MRL eliminated thermal oxidation from consideration as the maximum air pollution control capability for the heater's VOC emissions.

Good Combustion Practices
The only remaining available VOC emission control technology for H-5801 is good combustion practices, which will be an integral component of the design and operation of the heater.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that good combustion practices represent the maximum air pollution control capability for the VOC emissions from H-5801. Therefore, MRL will control VOC emissions from the heater by using good combustion practices and comply with the following emission limitation to reflect the performance of the maximum air pollution control capability for this unit:

- VOC emissions from the heater shall not exceed 0.0054 lb/MMBtu (HHV), based on the average of three 1-hour runs.

Additional Applicability:
Separate and distinct from the BACT analysis, the heater will be subject to the following work practice standards in 40 CFR, Part 63, Subpart DDDDD – *National Emission Standards for Hazardous Air Pollutants (NESHAP) for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters*: These requirements are applicable under ARM 17.8.749. These applicable requirements are included here as they further support federal requirements for maintaining proper equipment operation.

- 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. This optimization will be consistent with the manufacturer's specifications and any NO_x emission limitation requirement 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.

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 site with the capability to maintain good combustion practices at the heater.

The heater will not be subject to any NSPS or NESHAP PM, PM_{10} or $PM_{2.5}$ emission standard. However, it will be subject to the following MTDEQ 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; and
- Pursuant to ARM 17.8.309, PM emissions from the heater shall not exceed 0.24 lb/MMBtu.

Cogeneration Plant Turbine (Natural Gas)

The proposed Cogeneration Plant Turbine, with a maximum firing rate of 185 MMBtu/hr, can burn natural gas and renewable naphtha. This section presents the top-down BACT analysis performed for the turbine burning pipeline quality natural gas. The maximum air pollution control capability determinations made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-4** below, and details are presented in the subsequent sections, by pollutant.

A top-down BACT analysis for the turbine burning natural gas is presented below.

Table III-4
Proposed BACT Limits: Cogeneration Plant Turbine (Natural Gas)

Emissions Unit	Pollutant	Control Technology/Practice	Emissions Level
Cogeneration Plant Turbine fired with Natural Gas	CO	Catalytic Oxidation	0.008 lb/MMBtu (HHV) (Average of three 1-hour runs)
	NO_X – Steady State Operations	SCR	0.035 lb/MMBtu (HHV) (30-day rolling average)
	NO_X – SSM & SCR Warm-up Periods	NSPS Subpart KKKK Good Air Pollution Control Practices	58.45 lb/hr (SSM period average)
	PM (filt.)	Good Combustion Practices	0.0019 lb/MMBtu (HHV) (Average of three 1-hour runs)
	PM_{10} (filt. + cond.)	Good Combustion Practices	0.0066 lb/MMBtu (HHV) (Average of three 1-hour runs)
	$PM_{2.5}$ (filt. + cond.)	Good Combustion Practices	0.0066 lb/MMBtu (HHV) (Average of three 1-hour runs)
	SO_2	Low Sulfur Gaseous Fuel (Natural Gas)	Fuel gas containing ≤30 ppmv H_2S maximum and ≤10 ppmv H_2S on an annual average basis

Emissions Unit	Pollutant	Control Technology/Practice	Emissions Level
	VOC	Catalytic Oxidation	0.0021 lb/MMBtu (HHV) (Average of three 1-hour runs)

Carbon Monoxide

The turbine will emit CO due to the incomplete oxidation of hydrocarbons present in the natural gas. However, natural gas is a relatively low-carbon fuel. This fuel characteristic will promote low levels of CO emissions from the turbine.

Step 1: Identify Control Technologies

The following are available CO emission control technologies for the turbine.

- Good Combustion Practices;
- Thermal Oxidation; and
- Catalytic Oxidation.

Below these technologies are generally described.

Good Combustion Practices

Please see the Definition Section I herein for a discussion of this technology.

Thermal Oxidation

Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation

Please see the Definition Section III herein for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the CO emission control technologies determined to be available for the turbine is evaluated below.

Good Combustion Practices

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

Thermal Oxidation

Thermal oxidation is technically feasible for the control of CO emissions from the turbine.

Catalytic Oxidation

Catalytic oxidation is technically feasible for the turbine.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The remaining available CO emission control technologies for the cogeneration plant are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions.

- Catalytic Oxidation;
- Thermal Oxidation; and
- Good Combustion Practices.

Step 4: Evaluate Most Effective Control Options and Document Results
Below, MRL evaluated the cost effectiveness of the installation and operation of the CO emission control technologies that were determined to be technically feasible for the turbine.

Catalytic Oxidation

MRL has elected to install a catalytic oxidation technology, the most efficient control technology for this source and therefore does not need to conduct an economic impact analysis of this technology.

Thermal Oxidation

The oxidation of CO to CO_2 is a time-dependent chemical reaction. For a thermal oxidation system to effectively reduce CO, the process requires a wide combustion chamber specifically designed for increased residence time to allow the chemical reactions to complete. This design will increase the cost and require a large space to accommodate the device. Chamber residence time and temperature are directly linked. Shorter residence times (smaller chambers) require higher temperatures to achieve the same destruction rate, which increases fuel costs and can risk equipment damage.

Due to the low concentration of CO in the natural gas combustion exhaust stream, the application of thermal oxidation to reduce the turbine's CO emission rate would require either a large combustion chamber to provide sufficient reaction time or burning a considerable amount of fuel to achieve the elevated temperature necessary to promote the oxidation of the small amount of CO. Either option will increase the cost of having a thermal oxidizer for CO reduction.

Additionally, the addition of a second thermal oxidation process to the turbine system may not reduce the turbine's CO emissions by any appreciable amount, and this add-on control technology would considerably increase the energy requirements of the turbine system while notably increasing the amount of combustion pollutants, such as NO_x and CO_2, emitted into the atmosphere.

MRL estimated a capital cost of approximately $2,500,000 – $3,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the heater's CO emissions. Moreover, 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.

Research on emission control technology application data sets indicates thermal oxidation has not been used to control CO emissions from a comparable turbine.

Based on the above-described factors, MRL concluded that it would not be cost effective to install a thermal oxidizer for the turbine. Therefore, MRL eliminated thermal oxidation from consideration as the maximum air pollution control capability for the turbine's CO emissions.

Good Combustion Practices

MRL has elected to install a catalytic oxidation technology, the most efficient control technology for this source and therefore does not need to conduct an economic impact analysis of this technology.

Step 5: Select Maximum Air Pollution Control Capability

MRL determined that catalytic oxidation technology represent the maximum air pollution control capability for CO emissions from the cogeneration plant turbine's combustion of natural gas. Therefore, MRL will control CO emissions from the turbine by catalytic oxidation technology and complying with the following emission limitation:

- CO emissions from the cogeneration plant turbine shall not exceed 0.008 lb/MMBtu (HHV), based on 1-hr average as determined by three 1-hour runs.

Nitrogen Oxides

The cogeneration plant turbine will emit NO_x, primarily due to the thermal and prompt NO_x generation mechanisms because the turbine's natural gas will not contain appreciable amounts of organo-nitrogen compounds that result in fuel NO_x emissions. Thermal NO_x 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 internal combustion device. The rate of thermal NO_x generation is affected by the following three factors: oxygen concentration, peak flame temperature and the duration at peak flame temperature. As these three factors increase in value, the rate of thermal NO_x generation increases.

Prompt NO_x 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 NO_x may represent a meaningful portion of the NO_x emissions resulting from LNBs and ULNBs.

Step 1: Identify Control Technologies

The following are available NO_x emission control technologies for the cogeneration plant.

- LNBs/ULNBs;
- SCR;
- SNCR;
- NSCR; and
- Water-Steam Injection System.

Below these technologies are generally described.

LNBs/ULNBs
Please see the Definition IV herein for a discussion of this technology.

SCR
Please see the Definition V herein for a discussion of this technology.

SNCR
Please see the Definition VI herein for a discussion of this technology.

NSCR
Please see the Definition VII herein for a discussion of this technology

Water-Steam Injection System

A water-steam injection system is a control technology which reduces the production of NO_x by lowering the peak combustion temperature. The formation of NO_x emissions is highly temperature-dependent, so lowering the peak operational temperature can drastically reduce the amount of NO_x formed and emitted as combustion byproducts.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the NO_x emission control technologies determined to be available for the cogeneration plant turbine is evaluated below.

LNBs/ULNBs
This option is technically feasible for the turbine.

SCR
This option is technically feasible for the turbine.

SNCR
SNCR systems are not technically feasible for turbine due to the temperature regime.

NSCR
NSCR systems are not technically feasible for turbine due to the temperature regime.

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

- SCR;
- SNCR;
- ULNB;
- NSCR; and
- Water-Steam Injection System.

Step 4: Evaluate Most Effective Control Options and Document Results
MRL has elected to install an SCR, the most efficient control technology for this source and therefore does not need to conduct an economic impact analysis of these technologies.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that SCR technology represent the maximum air pollution control capability for the NO_x emissions from the cogeneration plant turbine during natural gas combustion. Therefore, MRL will control NO_x emissions from the turbine by equipping it with SCR technology and complying with the following emission limitation during its steady state operations:

- NO_x emissions from the cogeneration plant turbine, during steady state operations, shall not exceed 0.035 lb/MMBtu (HHV), based on a 30-day rolling average.

BACT for NOx during SSM, Fuel Switching, and SCR Warm-up Periods – Natural Gas
Step 1: Identify all Control Options

Available control options for steady state operation of the turbine considered:

- LNBS/ULBNs (Good Combustion Practices);
- SCR;
- SNCR; and
- NSCR.

Each of these technologies are described beginning in the Definition Section IV and are not repeated here.

In addition, MRL also evaluated potential ways to minimize the startup period, maintain optimal oxygen content and reduce NO_x emissions while maintaining and balancing turbine startup operating safety in accordance with the startup procedures. However, a cold startup process can take up to 24 hours and maintaining NO_x emissions in compliance with the short-term lb/MMBtu-based emission limits during the entire startup period can be challenging. To that end, MRL proposes the above-mentioned best management practices that would minimize emissions by reducing the duration of startup. Minimizing the duration of the startup combined with a higher lb/MMBtu limit to reflect steady state controls are not fully functional during these periods.

Step 2: Eliminate Technically Infeasible Options

During SSM periods, none of the add-on NO_x control devices are up to temperature to offer the level of NO_x control required for meeting the proposed lb/MMBtu permit limit. While the turbine can comply with the proposed 0.035 lb/MMBtu steady state BACT limit (as a 30-day rolling average) during steady state operations, the unit's emission rate during SSM periods and SCR warm-up periods may exceed 0.035 lb/MMBtu. However, the heat input to the turbine during SSM periods is expected to be low such that even at the elevated lb/MMBtu, the maximum short-term emissions (lb/hr) are not exceeded. MRL follows the prescribed startup procedure to start the turbine. Startup occurs at an acceptable maximum firing rate while maintaining safety and compliance with the equipment maximum pressure and temperature operating curve.

Therefore, SCR, SNCR and NSCR are each technically infeasible during these transient periods of startup, shutdown and malfunction.

To a limited degree good combustion practices are still viable during transient events, and the controls are already in place related to steady state operation proposed BACT.

Procedures associated with the transient periods, and an appropriate higher lb/MMBTU limit, particularly with startup, remain a viable control option for allowing efficient startup periods.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Both good combustion practices and following developed procedures for transient operation, particularly startup which requires longer warm-up times to avoid metal fatigue and other heat-related stresses, are available.

Step 4: Evaluate Most Effective -Control Options and Document Results

Good combustion practices and following developed procedures for minimizing transient durations are both effective. Combining good combustion practices and procedures, MRL has determined an expected lb/hr limit that could be achieved. The lb/hr-based SSM NO_x emission limit is determined based on the pre-SCR-controlled NOx emission rate of 0.29 lb/MMBtu and the turbine's maximum firing rate 185 MMBtu/hr, with an additional 10% safety factor applied. The resulting limit would provide for a 58.45 lb/hr limit calculated as an overall average of the transient period of a SSM event. MRL believes the shorter averaging period is reflective of the transient periods, the relatively low fuel rate during these periods, and effective procedures.

Step 5: Select BACT
MRL proposed Good Combustion Practices, use of developed procedures limiting transient period duration, and a NO_x emission limit of 58.45 lb/hr (over the transient period of a SSM event).

SSM periods are defined in Section IV of the permit and subject to ARM 17.8.749.

PM/PM10/PM2.5

The cogeneration plant turbine will emit PM, PM_{10} and $PM_{2.5}$ comprised of filterable and condensable portions. A gaseous fuel combustion device can emit PM, 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 turbine will combust pipeline quality natural gas, which is primarily comprised of relatively low molecular weight hydrocarbons. Therefore, elevated PM_{10} and $PM_{2.5}$ emissions from the turbine as a result of the incomplete combustion of high molecular weight hydrocarbons are not expected to occur. Additionally, the fuel will contain low levels of sulfur, further minimizing the generation of PM_{10} and $PM_{2.5}$ when it is combusted.

The turbine will not be subject to any NSPS or NESHAP PM emission standard. However, the turbine will be subject to the following NSPS Subpart KKKK work practice standards that will minimize its PM emissions.

- Pursuant to 40 CFR 60.4333(a), MRL will operate and maintain the stationary combustion turbine, air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

Additionally, it will be subject to the following MTDEQ opacity and PM standards.

- Pursuant to ARM 17.8.304(2), emissions from the turbine shall not exceed an opacity of 20% or greater averaged over 6 consecutive minutes; and
- Pursuant to ARM 17.8.309, PM emissions from the turbine shall not exceed 0.30 lb/MMBtu.

Step 1: Identify Control Technologies
The following are available PM, PM_{10} and $PM_{2.5}$ emission control technologies for the cogeneration plant.

- Good Combustion Practices;
- ESP;
- Filter;
- Wet Scrubber; and
- Cyclone.

Below these technologies are generally described.

Good Combustion Practices
Please see the Definition I herein for a discussion of this technology.

ESP
Please see the Definition VIII herein for a discussion of this technology.

Filter
Please see the Definition Section IX herein for a discussion of this technology.

Wet Scrubber
Please see the Definition Section X herein for a discussion of this technology.

Cyclone
Please see the Definition Section XI herein for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the PM, PM_{10} and $PM_{2.5}$ emission control technologies determined to be available for the cogeneration plant turbine is evaluated below.

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

ESP
MRL estimated that the PM emitted by the turbine 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 turbine's exhaust stream will be below the concentration typically seen in an ESP's exhaust stream. Thus, an ESP would not lower the turbine's PM_{10} emissions by any appreciable amount. Furthermore, research of emission control technology application data sets indicates an ESP has not been used to control PM emissions from a comparable turbine. These factors indicate it would not be technically feasible to use an ESP to control PM emissions from the turbine.

Baghouses / Fabric Filters
Baghouses/fabric filters are not used on natural gas-fired combustion units due to the inherently low filterable PM content of natural gas. Uncontrolled PM emissions from natural gas combustion are already on the order of ~0.001 to 0.003 lb/MMBtu, which is comparable to or below typical fabric filter outlet concentrations. Therefore, the installation of a baghouse would provide negligible emission reduction at disproportionate capital and operating cost.

Secondly, conventional filter bags have temperature limits, typically ranging from 275°F (e.g., standard polyester bags) to 500°F (e.g., fiberglass, Nomex, Teflon). Flue gas from fuel gas combustion of the turbine could melt or damage the filter material.

Thirdly, natural gas combustion produces a high volume of moisture in the flue gas. When the flue gas drops below its dew point, moisture can condense on the filter bags, which will cause the bags to become clogged as the fine condensable PM sticks to the wet fabric and thus will not lower the condensable PM emissions by any appreciable amount. Additionally, condensation can also cause corrosion to the baghouse's metal components, leading to material degradation and equipment failure.

Furthermore, research of EPA's RBLC database indicates a filter has not been used to control PM emissions from a comparable turbine.

These factors indicate it would not be technically feasible to use a baghouse / fabric filter to control PM emissions from the turbine. Wet Scrubber
The PM_{10}-only profile of the turbine's PM emissions indicates a wet scrubber would require a considerable pressure drop to effectively reduce the turbine's PM emissions. Additionally, the PM_{10} concentration in the turbine'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 emission control technology application data sets indicates a wet scrubber has not been used to control PM emissions from a comparable turbine. These factors indicate it would not be technically feasible to use a wet scrubber to control PM emissions from the turbine.

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

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The only remaining available PM, PM_{10} and $PM_{2.5}$ emission control technology for the cogeneration plant turbine is good combustion practices.

Step 4: Evaluate Most Effective Control Options and Document Results
The only remaining available PM, PM_{10} and $PM_{2.5}$ emission control technology for the cogeneration plant turbine is good combustion practices.

Step 5: Select Maximum Air Pollution Control Capability
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 cogeneration plant turbine during natural gas combustion. Therefore, MRL will control PM, PM_{10} and $PM_{2.5}$ emissions from the turbine by using good combustion practices and comply with the following emission limitations to reflect the performance of the maximum air pollution control capability for this unit:

- PM (filterable) emissions from the heater shall not exceed 0.0019 lb/MMBtu (HHV), based on the average of three 1-hour runs;
- PM_{10} emissions from the heater shall not exceed 0.0066 lb/MMBtu (HHV), based on the average of three 1-hour runs; and
- $PM_{2.5}$ emissions from the heater shall not exceed 0.0066 lb/MMBtu (HHV) based the average of three 1-hour runs.

Sulfur Dioxide

The cogeneration plant turbine will combust pipeline quality natural gas, which contains a negligible amount of H_2S. Therefore, the turbine will emit only a small amount of SO_2.

Step 1: Identify Control Technologies
The following are available SO_2 emission control technologies for the cogeneration plant turbine.

- Low Sulfur Fuel; and
- Flue Gas Desulfurization.

Below these technologies are generally described.

Low Sulfur Fuel
Please see the Definition Section XII herein for a discussion of this technology.

Flue Gas Desulfurization
Please see the Definition Section XIII herein for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the SO_2 emission control technologies determined to be available for the cogeneration plant is evaluated below.

Low Sulfur Fuel
Low sulfur fuel is technically feasible for the turbine.

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.

The turbine will emit SO_2 at concentrations less than 30 ppmv, which are below the concentrations oftentimes seen in a wet scrubber's exhaust stream. Flue gas desulfurization systems rely on efficient mass transfer of SO_2 from the gas stream into a liquid or solid absorbent. When the concentration of SO_2 is very low, the "driving force" for this mass transfer is extremely inefficient, which makes it difficult for the absorbent to capture the remaining sulfur molecules effectively.

Additionally, with low inlet SO_2 concentrations in flue gas, it is very challenging to control the system's chemistry and maintain the ideal pH for the scrubbing liquid, which further reduces removal efficiency.

Furthermore, 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 turbine.

Lastly, research of emission control technology application data sets indicated wet, semi-dry and dry scrubbers have not been used to control SO_2 emissions from a comparable turbine.

These factors indicate it would not be technically feasible to use flue gas desulfurization technologies to control SO_2 emissions from the turbine.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The only remaining available SO_2 emission control technology for the cogeneration plant is low sulfur fuel.

Step 4: Evaluate Most Effective Control Options and Document Results

The only remaining available SO_2 emission control technology for the cogeneration plant is low sulfur fuel.

Step 5: Select Maximum Air Pollution Control Capability

MRL determined that combusting low sulfur gaseous fuel represents the maximum air pollution control capability for the SO_2 emissions from the cogeneration plant turbine during natural gas combustion. Specifically, MRL will control SO_2 emissions from the cogeneration plant turbine by only combusting low sulfur gaseous fuels (natural gas) containing no more than 30 ppmv H_2S with an annual average of no more than 10 ppmv H_2S.

Volatile Organic Compounds

The cogeneration plant turbine will emit VOC due to the incomplete oxidation of hydrocarbons present in the turbine's gaseous fuel. However, the low molecular weight characteristic of the hydrocarbons in the fuel will promote low levels of VOC emissions from the turbine.

Step 1: Identify Control Technologies

The following are available VOC emission control technologies for the cogeneration plant.

- Good Combustion Practices;
- Thermal Oxidation; and
- Catalytic Oxidation.

Below these technologies are generally described.

Good Combustion Practices
Please see the Definition Section I herein for a discussion of this technology.

Thermal Oxidation
Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation
Please see the Definition Section III 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 cogeneration plant turbine is evaluated below.

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

Thermal Oxidation
Thermal oxidation is technically feasible for the control of VOC emissions from the turbine.

Catalytic Oxidation
Catalytic oxidation is technically feasible for the turbine.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The remaining available VOC emission control technologies for the cogeneration plant are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions.

- Catalytic Oxidation;
- Thermal Oxidation; and
- Good Combustion Practices

Step 4: Evaluate Most Effective Control Options and Document Results

Below, MRL evaluated the cost effectiveness of the installation and operation of the CO emission control technologies that were determined to be technically feasible for the turbine.

Catalytic Oxidation
MRL has elected to install a catalytic oxidation technology, the most efficient control technology for this source and therefore does not need to conduct an economic impact analysis of this technology.

Thermal Oxidation
Due to the very low concentration of VOC in its exhaust stream, the application of thermal oxidation to reduce the turbine'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 turbine'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 turbine system may not reduce the turbine's VOC emissions by any appreciable amount, and this add-on control technology would considerably increase the energy requirements of the turbine system while notably increasing the amount of combustion pollutants, such as NO_x and CO_2, emitted into the atmosphere.

Furthermore, research of emission control technology application data sets indicates thermal oxidation has not been used to control VOC emissions from a comparable turbine.

Lastly, MRL estimated a capital cost of approximately $2,500,000 – $3,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the heater's VOC emissions. Moreover, 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.

Based on the above-described factors, MRL concluded that it would not be cost effective to install a thermal oxidizer for the turbine. Therefore, MRL eliminated thermal oxidation from consideration as the maximum air pollution control capability for the turbine's VOC emissions.

Good Combustion Practices
MRL has elected to install a catalytic oxidation technology, the most efficient control technology for this source and therefore does not need to conduct an economic impact analysis of this technology.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that catalytic oxidation technology represent the maximum air pollution control capability for the VOC emissions from the cogeneration plant turbine during natural gas combustion. Therefore, MRL will control VOC emissions from the turbine by using catalytic oxidation technology and comply with the following emission limitation to reflect the performance of the maximum air pollution control capability for this unit:

- VOC emissions from the turbine shall not exceed 0.0021 lb/MMBtu (HHV), based on the average of three 1-hour runs.

Additional Applicability:

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

The turbine will not be subject to any NSPS or NESHAP CO emission standard. However, the turbine will be subject to the following NSPS Subpart KKKK work practice standards that will minimize its CO emissions.

- Pursuant to 40 CFR 60.4333(a), MRL will operate and maintain the stationary combustion turbine, air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

The turbine will be subject to the following NSPS Subpart KKKK NO_x emission standards.

- Pursuant to 40 CFR 60.4320(a), MRL will meet the below emission limits for NO_x
    - Natural Gas - 25 ppm at 15 percent O_2 or 1.2 lb/MWh of useful output.
- Pursuant to 40 CFR 60.4333(a), MRL will operate and maintain the stationary combustion turbine, air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

The turbine will be subject to the following NSPS Subpart KKKK work practice standards that will minimize its SO_2 emissions.

- Pursuant to 40 CFR 60.4330(a)(1), MRL will not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 0.90 pounds per megawatt-hour gross output;
- Pursuant to 40 CFR 60.4330(a)(2), MRL not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input; and
- Pursuant to 40 CFR 60.4333(a), MRL will operate and maintain the stationary combustion turbine, air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

The turbine will also be subject to the following MTDEQ SO_2 emission standard.

- Pursuant to ARM 17.8.322(5), the turbine 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).

Cogeneration Plant Turbine (Renewable Naphtha)

The maximum air pollution control capability determinations made for the turbine burning renewable naphtha pursuant to ARM 17.8.752 are presented below, by pollutant. **Table III-5** below summarizes the proposed BACT limits for this fuel scenario.

Table III-5
Proposed BACT Limits: Cogeneration Plant Turbine (Renewable Naphtha)

Emissions Unit	Pollutant	Control Technology/Practice	Emissions Level
Cogeneration Plant Turbine fired with Renewable Naphtha	CO	Catalytic Oxidation	0.008 lb/MMBtu (HHV) (Average of three 1-hour runs)
	NO_X – Steady State Operations	SCR	0.035 lb/MMBtu (HHV) (30-day rolling average)
	NO_X – SSM & SCR Warm-up Periods	NSPS Subpart KKKK Good Air Pollution Control Practices	61.67 lb/hr (SSM period average)
	PM (filt.)	Good Combustion Practices	0.0043 lb/MMBtu (HHV) (Average of three 1-hour runs)
	PM_{10} (filt. + cond.)	Good Combustion Practices	0.012 lb/MMBtu (HHV) (Average of three 1-hour runs)
	$PM_{2.5}$ (filt. + cond.)	Good Combustion Practices	0.012 lb/MMBtu (HHV) (Average of three 1-hour runs)
	SO_2	Low Sulfur Fuel (Renewable Light Naphtha)	Low Sulfur Fuel containing ≤30 ppm by weight sulfur on an annual average
	VOC	Catalytic Oxidation	0.004 lb/MMBtu (HHV) (Average of three 1-hour runs)

Carbon Monoxide

The turbine will emit CO due to the incomplete oxidation of hydrocarbons present in the light naphtha. However, light naphtha is a relatively low-carbon fuel. This fuel characteristic will promote low levels of CO emissions from the turbine.

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

The turbine will not be subject to any NSPS or NESHAP CO emission standard. However, the turbine will be subject to the following NSPS Subpart KKKK work practice standards that will minimize its CO emissions.

- Pursuant to 40 CFR 60.4333(a), MRL will operate and maintain the stationary combustion turbine, air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

Step 1: Identify Control Technologies

The following are available CO emission control technologies for the turbine.

- Good Combustion Practices;
- Thermal Oxidation; and
- Catalytic Oxidation.

Below these technologies are generally described.

Good Combustion Practices
Please see the Definition Section I herein for a discussion of this technology.

Thermal Oxidation
Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation
Please see the Definition Section III herein for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the CO emission control technologies determined to be available for the turbine is evaluated below.

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

Thermal Oxidation
Thermal oxidation is technically feasible for the control of CO emissions from the turbine.

Catalytic Oxidation
Catalytic oxidation is technically feasible for the turbine.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The remaining available CO emission control technologies for the cogeneration plant are listed below from the highest to lowest potential emission control relative to the emissions unit's baseline emissions.

- Catalytic Oxidation;
- Thermal Oxidation; and
- Good Combustion Practices.

Step 4: Evaluate Most Effective Control Options and Document Results
Below we evaluate the cost effectiveness of the installation and operation of the CO emission control technologies.

Catalytic Oxidation
MRL has elected to install a catalytic oxidation technology, the most efficient control technology for this source and therefore does not need to conduct an economic impact analysis of this technology.

Thermal Oxidation
As described previously, the oxidation of CO to CO_2 is a time-dependent chemical reaction. For a thermal oxidation system to effectively reduce CO, the process requires a wide combustion chamber specifically designed for increased residence time to allow the chemical reactions to complete. This design will increase the cost and require a large space to accommodate the device. Chamber residence time and temperature are directly linked. Shorter residence times (smaller chambers) require higher temperatures to achieve the same destruction rate, which increases fuel costs and can risk equipment damage.

Due to the low concentration of CO in the renewable naphtha combustion exhaust stream, the application of thermal oxidation to reduce the turbine's CO emission rate would require either a large combustion chamber to provide sufficient reaction time or burning a considerable amount of fuel to achieve the elevated temperature necessary to promote the oxidation of the small amount of CO. Either option will increase the cost of having a thermal oxidizer for CO reduction.

Additionally, the addition of a second thermal oxidation process to the turbine system may not reduce the turbine's CO emissions by any appreciable amount, and this add-on control technology would considerably increase the energy requirements of the turbine system while notably increasing the amount of combustion pollutants, such as CO, NO_x and CO_2, emitted into the atmosphere.

Furthermore, research of emission control technology application data sets indicates thermal oxidation has not been used to control CO emissions from a comparable turbine.

MRL estimated a capital cost of approximately $2, 500,000 – $3,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the heater's CO emissions. Moreover, 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.

Based on the above-described factors, MRL concluded that it would not be cost effective to install a thermal oxidizer for the turbine. Therefore, MRL eliminated thermal oxidation from consideration as the maximum air pollution control capability for the turbine's CO emissions.

Good Combustion Practices
MRL has elected to install a catalytic oxidation technology, the most efficient control technology for this source and therefore does not need to conduct an economic impact analysis of this technology.

Step 5: Select Maximum Air Pollution Control Capability

MRL determined that catalytic oxidation technology represent the maximum air pollution control capability for CO emissions from the cogeneration plant turbine during renewable naphtha combustion. Therefore, MRL will control CO emissions from the turbine by using catalytic oxidation technology and complying with the following emission limitation:

- CO emissions from the cogeneration plant turbine shall not exceed 0.008 lb/MMBtu (HHV), based on 1-hr average as determined by the average of three 1-hour runs.

Nitrogen Oxides

The cogeneration plant turbine will emit NO_x, primarily due to the thermal and prompt NO_x generation mechanisms because the turbine's renewable naphtha will not contain appreciable amounts of organo-nitrogen compounds that result in fuel NO_x emissions. Thermal NO_x 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 internal combustion device. The rate of thermal NO_x generation is affected by the following three factors: oxygen concentration, peak flame temperature and the duration at peak flame temperature. As these three factors increase in value, the rate of thermal NO_x generation increases.

Prompt NO_x 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 NO_x may represent a meaningful portion of the NO_x emissions resulting from LNBs and ULNBs.

The turbine will be subject to the following NSPS Subpart KKKK NO_x emission standards.

- Pursuant to 40 CFR 60.4320(a), MRL will meet the below emission limits for NO_x
    - Renewable Naphtha - 74 ppm at 15 percent O_2 or 3.6 lb/MWh of useful output.
- Pursuant to 40 CFR 60.4333(a), MRL will operate and maintain the stationary combustion turbine, air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

Step 1: Identify Control Technologies

The following are available NO_x emission control technologies for the cogeneration plant.

- LNBs/ULNBs;
- SCR;
- SNCR;
- NSCR; and
- Water-Steam Injection System.

Below these technologies are generally described.

LNBs/ULNBs

Please see the Definition Section I herein for a discussion of this technology.

SCR
Please see the Definition Section V herein for a discussion of this technology.

SNCR
Please see the Definition Section VI herein for a discussion of this technology.

NSCR
Please see the Definition Section VII herein for a discussion of this technology

Water-Steam Injection System
A water-steam injection system is a control technology which reduces the production of NOx by lowering the peak combustion temperature. The formation of NOx emissions is highly temperature-dependent, so lowering the peak operational temperature can drastically reduce the amount of NOx formed and emitted as combustion byproducts.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the NO_x emission control technologies determined to be available for the cogeneration plant turbine is evaluated below.

LNBs/ULNBs
This option is technically feasible for the turbine.

SCR
This option is technically feasible for the turbine.

SNCR
SNCR systems are not technically feasible for turbine due to the temperature regime.

NSCR
NSCR systems are not technically feasible for turbine due to the temperature regime.

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

- SCR;
- SNCR;
- ULNB;
- NSCR; and
- Water-Steam Injection System.

Step 4: Evaluate Most Effective Control Options and Document Results
MRL has elected to install a SCR, the most efficient control technology for this source and therefore does not need to conduct an economic impact analysis of these technologies.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that SCR technology represent the maximum air pollution control capability for the NO_x emissions from the cogeneration plant turbine during renewable naphtha combustion.

Therefore, MRL will control NO_x emissions from the turbine by equipping it with SCR technology and complying with the following emission limitation:

- NO_x emissions from the cogeneration plant turbine, during steady state operations, shall not exceed 0.035 lb/MMBtu (HHV), based on a 30-day rolling average.

BACT for NOx during SSM, Fuel Switching, and SCR Warm-up Periods – Liquid Naphtha

Step 1: Identify all Control Options
Available control options for steady state operation of the turbine considered:

- LNBS/ULBNs (Good Combustion Practices);
- SCR;
- SNCR; and
- NSCR.

Each of these technologies are described beginning in the Definition IV and are not repeated here.

In addition, MRL also evaluated potential ways to minimize the startup period, maintain optimal oxygen content and reduce NO_x emissions while maintaining and balancing turbine startup operating safety in accordance with the startup procedures. However, a cold startup process can take up to 24 hours and maintaining NO_x emissions in compliance with the short-term lb/MMBtu-based emission limits during the entire startup period can be challenging. To that end, MRL proposes the above-mentioned best management practices that would minimize emissions by reducing the duration of startup. Minimizing the duration of the startup combined with a higher lb/MMBtu limit to reflect steady state controls are not fully functional during these periods.

Step 2: Eliminate Technically Infeasible Options
During SSM periods, none of the add-on NO_x control devices are up to temperature to offer the level of NO_x control required for meeting the proposed lb/MMBtu permit limit. While the turbine can comply with the proposed 0.035 lb/MMBtu steady state BACT limit (as a 30-day rolling average) during steady state operations, the unit's emission rate during SSM periods and SCR warm-up periods may exceed 0.035 lb/MMBtu. However, the heat input to the turbine during SSM periods is expected to be low such that even at the elevated lb/MMBtu, the maximum short-term emissions (lb/hr) are not exceeded. MRL follows the prescribed startup procedure to start the turbine. Startup occurs at an acceptable maximum firing rate while maintaining safety and compliance with the equipment maximum pressure and temperature operating curve.

Therefore, SCR, SNCR and NSCR are each technically infeasible during these transient periods of startup, shutdown and malfunction.

To a limited degree good combustion practices are still viable during transient events, and the controls are already in place related to steady state operation proposed BACT.

Procedures associated with the transient periods, and an appropriate higher lb/MMBTU limit, particularly with startup, remain a viable control option for allowing efficient startup periods.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
Both good combustion practices and following developed procedures for transient operation, particularly startup which requires longer warm-up times to avoid metal fatigue and other heat-related stresses, are available.

Step 4: Evaluate Most Effective -Control Options and Document Results
Good combustion practices and following developed procedures for minimizing transient durations are both effective. Combining good combustion practices and procedures, MRL has determined an expected lb/hr limit that could be achieved. The lb/hr-based SSM NO_x emission limit is determined based on the pre-SCR-controlled NOx emission rate of 0.30 lb/MMBtu and the turbine's maximum firing rate 185 MMBtu/hr, with an additional 10% safety factor applied. The resulting limit would provide a 61.67 lb/hr limit calculated as an overall average over the entire transient period of an SSM event.

Step 5: Select BACT

MRL proposed Good Combustion Practices, use of developed procedures limiting transient period duration, and a NO_x emission limit of 61.67 lb/hr (over the transient period of each SSM event).

SSM periods are defined in Section IV of the permit and subject to ARM 17.8.749.

PM/PM10/PM2.5

The cogeneration plant turbine will emit PM, PM_{10} and $PM_{2.5}$ comprised of filterable and condensable portions. A gaseous fuel combustion device can emit PM, PM_{10} and $PM_{2.5}$ at elevated levels due to the incomplete combustion of higher molecular weight hydrocarbons present in the device's fuel. However, the turbine will combust renewable naphtha, which is primarily comprised of hydrogen and relatively low molecular weight hydrocarbons. Therefore, elevated PM_{10} and $PM_{2.5}$ emissions from the turbine 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 turbine will not be subject to any NSPS or NESHAP PM emission standard. However, the turbine will be subject to the following NSPS Subpart KKKK work practice standards that will minimize its PM emissions.

- Pursuant to 40 CFR 60.4333(a), MRL will operate and maintain the stationary combustion turbine, air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

Additionally, it will be subject to the following MTDEQ opacity and PM standards.

- Pursuant to ARM 17.8.304(2), emissions from the turbine shall not exceed an opacity of 20% or greater averaged over 6 consecutive minutes.
- Pursuant to ARM 17.8.309, PM emissions from the turbine shall not exceed 0.29 lb/MMBtu.

Step 1: Identify Control Technologies
The following are available PM, PM_{10} and $PM_{2.5}$ emission control technologies for the cogeneration plant.

- Good Combustion Practices;
- ESP;
- Filter;
- Wet Scrubber; and
- Cyclone.

Below these technologies are generally described.

Good Combustion Practices
Please see the Definition Section I herein for a discussion of this technology.

ESP
Please see the Definition Section VIII herein for a discussion of this technology.

Filter
Please see the Definition Section IX herein for a discussion of this technology.

Wet Scrubber
Please see the Definition Section X herein for a discussion of this technology.

Cyclone
Please see the Definition Section XI herein for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options
The technical feasibility of the PM, PM_{10} and $PM_{2.5}$ emission control technologies determined to be available for the cogeneration plant turbine is evaluated below.

Good Combustion Practices

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

ESP

MRL estimated that the PM emitted by the turbine 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 turbine's exhaust stream will be below the concentration typically seen in an ESP's exhaust stream. Thus, an ESP would not lower the turbine's PM_{10} emissions by any appreciable amount. Furthermore, research of emission control technology application data sets indicates an ESP has not been used to control PM emissions from a comparable turbine. These factors indicate it would not be technically feasible to use an ESP to control PM emissions from the turbine.

Filter

Baghouses/fabric filters are not used on natural gas-fired combustion units due to the inherently low filterable PM content of natural gas. Uncontrolled filterable PM emissions from natural gas combustion are already on the order of ~0.005 lb/MMBtu, which is comparable to or below typical fabric filter outlet concentrations. Therefore, the installation of a baghouse would provide negligible emission reduction at disproportionate capital and operating cost.

Secondly, conventional filter bags have temperature limits, typically ranging from 275°F (e.g., standard polyester bags) to 500°F (e.g., fiberglass, Nomex, Teflon). Flue gas from fuel gas combustion of the turbine could melt or damage the filter material.

Thirdly, natural gas combustion produces a high volume of moisture in the flue gas. When the flue gas drops below its dew point, moisture can condense on the filter bags, which will cause the bags to become clogged as the fine condensable PM sticks to the wet fabric and thus will not lower the condensable PM emissions by any appreciable amount. Additionally, condensation can also cause corrosion to the baghouse's metal components, leading to material degradation and equipment failure.

Furthermore, research of EPA's RBLC database indicates a filter has not been used to control PM emissions from a comparable turbine.

These factors indicate it would not be technically feasible to use a baghouse / fabric filter to control PM emissions from the turbine.

Wet Scrubber

The PM_{10}-only profile of the turbine's PM emissions indicates a wet scrubber would require a considerable pressure drop to effectively reduce the turbine's PM emissions. Additionally, the PM_{10} concentration in the turbine'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 emission control technology application data sets indicates a wet scrubber has not been used to control PM emissions from a comparable turbine. These factors indicate it would not be technically feasible to use a wet scrubber to control PM emissions from the turbine.

Cyclone

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

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The only remaining available PM, PM_{10} and $PM_{2.5}$ emission control technology for the cogeneration plant turbine is good combustion practices.

Step 4: Evaluate Most Effective Control Options and Document Results

The only remaining available PM, PM_{10} and $PM_{2.5}$ emission control technology for the cogeneration plant turbine is good combustion practices.

Step 5: Select Maximum Air Pollution Control Capability
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 cogeneration plant turbine during renewable naphtha combustion. Therefore, MRL will control PM, PM_{10} and $PM_{2.5}$ emissions from the turbine by using good combustion practices and comply with the following emission limitations to reflect the performance of the maximum air pollution control capability for this unit:

- PM (filterable) emissions from the heater shall not exceed 0.0043 lb/MMBtu (HHV), based on the average of three 1-hour runs;
- PM_{10} emissions from the heater shall not exceed 0.012 lb/MMBtu (HHV), based on the average of three 1-hour runs; and
- $PM_{2.5}$ emissions from the heater shall not exceed 0.012 lb/MMBtu (HHV) based on the average of three 1-hour runs.

Sulfur Dioxide
The cogeneration plant turbine will combust renewable naphtha. The renewable naphtha will contain a negligible amount of H_2S. Therefore, the turbine will emit only a small amount of SO_2.

The turbine will be subject to the following NSPS Subpart KKKK work practice standards that will minimize its SO_2 emissions.

- Pursuant to 40 CFR 60.4330(a)(1), MRL will not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 0.90 pounds per megawatt-hour gross output;
- Pursuant to 40 CFR 60.4330(a)(2), MRL not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input; and
- Pursuant to 40 CFR 60.4333(a), MRL will operate and maintain the stationary combustion turbine, air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

Step 1: Identify Control Technologies
The following are available SO_2 emission control technologies for the cogeneration plant turbine.

- Low Sulfur Fuel; and
- Flue Gas Desulfurization.

Below these technologies are generally described.

Low Sulfur Fuel
Please see the Definition Section XII herein for a discussion of this technology.

Flue Gas Desulfurization
Please see the Definition Section XIII herein for a discussion of this technology.

Step 2: Eliminate Technically Infeasible Options

The technical feasibility of the SO_2 emission control technologies determined to be available for the cogeneration plant is evaluated below.

Low Sulfur Fuel
Low sulfur fuel is technically feasible for the turbine.

Flue Gas Desulfurization
Flue gas desulfurization is commonly used to reduce SO_2 emissions from coal-fired and oil- fired combustion sources that have relatively high concentration of SO_2 (thousands of ppmv) contained in the flue gas generated by these sources. The renewable naphtha will contain a negligible amount of H_2S. The turbine will emit SO_2 at concentrations less than 30 ppmv, which are below the concentrations oftentimes seen in a wet scrubber's exhaust stream. Flue gas desulfurization systems rely on efficient mass transfer of SO_2 from the gas stream into a liquid or solid absorbent. When the concentration of SO_2 is very low, the "driving force" for this mass transfer is extremely inefficient, which makes it difficult for the absorbent to capture the remaining sulfur molecules effectively.

Additionally, with low inlet SO_2 concentrations in flue gas, it is very challenging to control the system's chemistry and maintain the ideal pH for the scrubbing liquid, which further reduces removal efficiency.

Moreover, 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 turbine.

Lastly, research of emission control technology application data sets indicated wet, semi-dry and dry scrubbers have not been used to control SO_2 emissions from a comparable turbine.

These factors indicate it would not be technically feasible to use flue gas desulfurization technologies to control SO_2 emissions from the turbine.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The only remaining available SO_2 emission control technology for the cogeneration plant is low sulfur fuel.

Step 4: Evaluate Most Effective Control Options and Document Results

The only remaining available SO_2 emission control technology for the cogeneration plant is low sulfur fuel.

Step 5: Select Maximum Air Pollution Control Capability

MRL determined that combusting low sulfur gaseous fuel represents the maximum air pollution control capability for the SO_2 emissions from the cogeneration plant turbine. Specifically, MRL will control SO_2 emissions from the cogeneration plant turbine by combusting liquid fuel containing an annual average of no more than 30 ppm by weight of sulfur content.

Volatile Organic Compounds

The cogeneration plant turbine will emit VOC due to the incomplete oxidation of hydrocarbons present in the turbine's fuel. However, the low molecular weight characteristic of the hydrocarbons in the fuel will promote low levels of VOC emissions from the turbine.

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

The turbine will not be subject to any NSPS or NESHAP VOC emission standard. However, the turbine will be subject to the following NSPS Subpart KKKK work practice standards that will minimize its VOC emissions.

- Pursuant to 40 CFR 60.4333(a), MRL will operate and maintain the stationary combustion turbine, air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for the cogeneration plant.

- Good Combustion Practices;
- Thermal Oxidation; and
- Catalytic Oxidation.

Below these technologies are generally described.

Good Combustion Practices
Please see the Definition Section I herein for a discussion of this technology.

Thermal Oxidation
Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation
Please see the Definition Section III 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 cogeneration plant turbine is evaluated below.

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

Thermal Oxidation

Thermal oxidation is technically feasible for the control of VOC emissions from the turbine.

Catalytic Oxidation

Catalytic oxidation is technically feasible for the turbine.

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

- Catalytic Oxidation;
- Thermal Oxidation; and
- Good Combustion Practices.

Step 4: Evaluate Most Effective Control Options and Document Results
Below, MRL evaluated the cost effectiveness of the installation and operation of the VOC emission control technologies that were determined to be technically feasible for the turbine.

Catalytic Oxidation

MRL has elected to install a catalytic oxidation technology, the most efficient control technology for this source and therefore does not need to conduct an economic impact analysis of this technology.

Thermal Oxidation

Due to the very low concentration of VOC in its exhaust stream, the application of thermal oxidation to reduce the turbine'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 turbine'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 turbine system may not reduce the turbine's VOC emissions by any appreciable amount, and this add-on control technology would considerably increase the energy requirements of the turbine system while notably increasing the amount of combustion pollutants, such as NO_x and CO_2, emitted into the atmosphere.

Furthermore, research of emission control technology application data sets indicates thermal oxidation has not been used to control VOC emissions from a comparable turbine.

Lastly, MRL estimated a capital cost of approximately $2,500,000 – $3,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the heater's VOC emissions. Moreover, 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.

Based on the above-described factors, MRL concluded that it would not be cost effective to install a thermal oxidizer for the turbine. Therefore, MRL eliminated thermal oxidation from consideration as the maximum air pollution control capability for the turbine's VOC emissions.

Good Combustion Practices

MRL has elected to install a catalytic oxidation technology, the most efficient control technology for this source and therefore does not need to conduct an economic impact analysis of this technology.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that catalytic oxidation technology represents the maximum air pollution control capability for the VOC emissions from the cogeneration plant turbine during renewable naphtha combustion. Therefore, MRL will control VOC emissions from the turbine by using catalytic oxidation technology and comply with the following emission limitation to reflect the performance of the maximum air pollution control capability for this unit:

- VOC emissions from the heater shall not exceed 0.004 lb/MMBtu (HHV), based on the average of three 1-hour runs.

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Additional Applicability:

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

The turbine will not be subject to any NSPS or NESHAP CO emission standard. However, the turbine will be subject to the following NSPS Subpart KKKK work practice standards that will minimize its CO emissions.

- Pursuant to 40 CFR 60.4333(a), MRL will operate and maintain the stationary combustion turbine, air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

SSM Limits for Existing Heaters H-4101, H-4102, H-3815A/B, and H-4601

For the existing heaters H-4101, H-4102, H-3815A/B, and H-4601, MRL conducted the following top-down 5-step BACT analysis to establish a lb/hr-based NO_x emission limit for each heater during SSM periods of the fuel combustion units.

Step 1: Identify all Control Options
In the original BACT analyses for the listed existing heaters, available control options for steady state operation of these heaters considered:

- LNBS/ULBNs (Good Combustion Practices);
- SCR;
- SNCR; and
- NSCR.

Each of these technologies was described in the original BACT analyses that were previously submitted to and approved by the MTDEQ for these existing heaters. These technologies are not repeated here.

In addition, MRL evaluated potential ways to minimize the startup period, maintain optimal oxygen content and reduce NOx emissions from each heater while maintaining and balancing heater startup operating safety in accordance with the startup procedures. However, a cold startup process can normally take up to 24 hours and maintaining NOx emissions in compliance with the short-term lb/MMBtu-based emission limits during the entire startup period can be challenging. To that end, MRL proposes the above-mentioned best management practices that would minimize emissions by reducing the duration of startup. Minimizing the duration of the startup combined with a higher lb/MMBtu limit to reflect steady state controls are not fully functional during these periods.

Step 2: Eliminate Technically Infeasible Options
During SSM periods, none of the add-on NO_x control devices are up to temperature to offer the level of NO_x control required for meeting the existing lb/MMBtu permit limit of each heater. While each existing heater can comply with its lb/MMBtu steady state BACT limit (as a 30-day rolling average) during steady state operations, its emission rate during SSM periods may exceed the existing lb/MMBtu limit during those events. However, the heat input to each heater during SSM periods is expected to be low such that even at the elevated lb/MMBtu, the maximum short-term lb/hr emissions are not exceeded. MRL follows the prescribed startup procedure to start each heater. Startup occurs at an acceptable maximum firing rate while maintaining safety and compliance with the equipment maximum pressure and temperature operating curve.

Therefore, SCR, SNCR and NSCR are each technically infeasible during these transient periods of startup, shutdown and malfunction.

To a limited degree good combustion practices and equipping each heater with ULBNs are still viable during transient events, and the controls are already in place related to steady state operation BACT.

Procedures associated with the transient periods, and an appropriate higher lb/MMBTU limit, particularly with startup, remain a viable control option for allowing efficient startup periods.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
Both good combustion practices and following developed procedures for transient operation, particularly startup which requires longer warm-up times to avoid metal fatigue and other heat-related stresses, are available.

Step 4: Evaluate Most Effective -Control Options and Document Results
Good combustion practices and following developed procedures for minimizing transient durations are both effective. Combining good combustion practices and procedures, MRL has determined an expected lb/hr limit that could be achieved for each existing heater. The lb/hr-based SSM NOx emission limit is determined based on the existing stead-state BACT limit of each heater and the heater's maximum firing rate, with an additional 10% safety factor applied. The resulting lb/hr limit of each existing heater (calculated as an overall average over the transient period of an SSM event) is listed in **Table III-6** below.

Step 5: Select BACT
MRL proposed Good Combustion Practices, use of developed procedures limiting transient period duration, and the BACT limit in the unit of lb/hr as shown in **Table III-6** below for each listed existing heater. SSM definitions are located in Section IV of the permit.

Table III-6
Proposed BACT Limits for NOx Emissions During SSM Periods: Existing Heaters

Heater	Proposed SSM Limit
H-4101 (RFU Combined Feed Heater)	2.10 lb/hr*
H-4102 (RFU Fractionator Feed Heater)	1.67 lb/hr*
H-3815A and B (Hydrogen Plant #3 Reformer Heaters combined)	7.24 lb/hr*

H-4601 (Hydrogen Plant #4 Reformer Heater)	9.37 lb/hr*

* Each of the listed SSM limits is calculated as an overall average over the transient period of an SSM event.

SSM periods are defined in Section IV of the permit and subject to ARM 17.8.749.

BACT Tank Analysis

Existing Renewable Fuel Product Storage Tank 29

Tank #29 is an existing atmospheric fixed roof storage tank storing renewable diesel. As presented above in the application materials, MRL proposes to use Tank #29 for storage of renewable fuel products with a vapor pressure equal to or less than the vapor pressure of renewable kerosene/SAF to provide some operational flexibility. Potential VOC emissions from this tank have been updated based on storing renewable kerosene/SAF, which has the highest vapor pressure amount of the fuel products that will be potentially stored in this tank. No physical modifications will be made to this tank.

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-7** below and the details are presented in the subsequent sections.

Table III-7
Proposed BACT Limits: Storage Tank #29

Emissions Unit	Pollutant	Control Technology/Practice
Existing Tank #29	VOC	Vertical fixed roof with submerged fill

Volatile Organic Compounds

The emissions mechanisms for the storage tank include 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.

Since renewable kerosene/SAF has a higher vapor pressure than RD and the annual product throughput to the tank will increase, potential VOC emissions from this tank will increase. Tank #29 is not/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 #29.

- 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;

- External Floating Roof (EFR) Storage Tank; and
- 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
Below, we evaluate the technical feasibility of the VOC emission control technologies determined to be available for Tank #29.

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 is 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; and
- 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 and Document Results
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 approximately $1,250,000 – $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that the tank's VOC emissions cannot be safely routed to the adjacent CMR Great Falls Refinery's flare system because that flare system does not allow oxygen ingress. 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 3.27 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 approximately $1,250,000 to $2,000,000 , which is not cost effective in consideration of the 3.25 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 3.27 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 3.27 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.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill is an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that the original BACT analysis and determination, i.e., fixed roof with submerged fill, still represents the maximum air pollution control capacity for the VOC emissions from Tank #29. No physical modifications will be made to this tank or its existing control technology.

Existing Renewable Product Storage Tank 116

Tank #116 is an existing atmospheric fixed roof storage tank storing renewable diesel. As presented above in the application materials, MRL proposes to use Tank #116 for storage of renewable fuel products with a vapor pressure equal to or less than the vapor pressure of renewable kerosene/SAF to provide operational flexibility. Potential VOC emissions from this tank have been conservatively updated based on storing renewable kerosene/SAF, which has the highest vapor pressure amount of the fuel products that will be potentially stored in this tank. No physical modifications will be made to this tank.

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-8** below and the details are presented in the subsequent sections.

Table III-8
Proposed BACT Limits: Storage Tank #116

Emissions Unit	Pollutant	Control Technology/Practice
Existing Tank #116	VOC	Vertical fixed roof with submerged fill

Volatile Organic Compounds

The emissions mechanisms for the storage tank include 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.

Since renewable kerosene/SAF has a higher vapor pressure than renewable diesel, potential VOC emissions from this tank will increase. Tank #116 is not/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 #116.

- 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
Please see the Definition Section XV herein for a discussion of this technology.

IFR Storage Tank
Please see the Definition Section XVI herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 #128.

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 is 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; and
- 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 and Document Results
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 approximately $1,250,000 – $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 4.76 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 approximately $1,250,000 – $2,000,000, which is not cost effective in consideration of the 4.76 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 4.76 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 4.76 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.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill is an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that the original BACT analysis and determination, i.e., fixed roof with submerged fill, still represents the maximum air pollution control capacity for the VOC emissions from Tank #116. No physical modifications will be made to this tank or its existing control technology

Existing Renewable Product Storage Tank 128

Tank #128 is an existing atmospheric fixed roof storage tank storing renewable diesel. As presented above in the application materials, MRL proposes to use Tank #128 for storage of renewable fuel products with a vapor pressure equal to or less than the vapor pressure of renewable kerosene/SAF to provide operational flexibility. Potential VOC emissions from this tank have been updated based on storing renewable kerosene/SAF, which has the highest vapor pressure amount of the fuel products that will be potentially stored in this tank. No physical modifications will be made to this tank.

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-9** below and the details are presented in the subsequent sections.

Table III-9
Proposed BACT Limits: Storage Tank #128

Emissions Unit	Pollutant	Control Technology/Practice
Existing Tank #128	VOC	Vertical fixed roof with submerged fill

Volatile Organic Compounds

The emissions mechanisms for the storage tank include 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.

Since renewable kerosene/SAF has a higher vapor pressure than renewable diesel and the annual product throughput to the tank will increase, potential VOC emissions from this tank will increase. Tank #128 is not/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 #128.

- 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

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

IFR Storage Tank
Please see the Definition Section XVI herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 #128.

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 is 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; and
- 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 and Document Results
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 approximately $1,250,000 – $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 3.45 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 approximately $1,250,000 – $2,000,000, which is not cost effective in consideration of the 3.45 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 3.45 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 3.45 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.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill is an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that the original BACT analysis and determination, i.e., fixed roof with submerged fill, still represents the maximum air pollution control capacity for the VOC emissions from Tank #128. No physical modifications will be made to this tank or its existing control technology.

Existing Renewable Product Storage Tank 301

Tank #301 is an existing atmospheric fixed roof storage tank storing renewable feed. No physical or stored material changes are proposed for this tank, but the annual throughput renewable feed to Tank #301 will increase due to the MaxSAF® Project and therefore, potential VOC emissions from this tank will increase. As such, a BACT analysis is being conducted for this tank. The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-10** below and the details are presented in the subsequent sections.

Table III-10
Proposed BACT Limits: Storage Tank #301 (Renewable Feed)

Emissions Unit	Pollutant	Control Technology/Practice
Existing Tank #301	VOC	Vertical fixed roof with submerged fill

Volatile Organic Compounds

The emissions mechanisms for the storage tank include 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 #301 is not/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 #301.

- 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
Please see the Definition Section XV herein for a discussion of this technology.

IFR Storage Tank
Please see the Definition Section XVI herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 #301.

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 is 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; and

- 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 and Document Results
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 approximately $1,250,000 to $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 0.65 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 approximately $1,250,000 to $2,000,000, which is not cost effective in consideration of the 0.65 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 0.65 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 0.65 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.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill is an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that the original BACT analysis and determination, i.e., fixed roof with submerged fill, still represents the maximum air pollution control capacity for the VOC emissions from Tank #301. No physical modifications will be made to this tank or its existing control technology.

Existing Renewable Product Storage Tank 302

Tank #302 is an existing atmospheric fixed roof storage tank storing renewable feed. No physical or stored material changes are proposed for this tank, but the annual throughput of renewable feed to Tank #302 will increase due to the MaxSAF® Project and therefore, potential VOC emissions from this tank will increase. As such, a BACT analysis is being conducted for this tank.

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-11** below and the details are presented in the subsequent sections.

Table III-11
Proposed BACT Limits: Storage Tank #302 (Renewable Feed)

Emissions Unit	Pollutant	Control Technology/Practice
Existing Tank #302	VOC	Vertical fixed roof with submerged fill

Volatile Organic Compounds
The emissions mechanisms for the storage tank include 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 #302 is not/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 #302.

- 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
Please see the Definition Section XV herein for a discussion of this technology.

IFR Storage Tank
Please see the Definition Section XVI herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 #302.

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 is 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; and
- 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 and Document Results
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 approximately $1,250,000 – $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 0.58 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 approximately $1,250,000 – $2,000,000, which is not cost effective in consideration of the 0.58 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 0.58 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 0.58 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.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill is an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that the original BACT analysis and determination, i.e., fixed roof with submerged fill, still represents the maximum air pollution control capacity for the VOC emissions from Tank #302. No physical modifications will be made to this tank or its existing control technology.

Existing Renewable Product Storage Tank 303

Tank #303 is an existing atmospheric fixed roof storage tank storing renewable feed. No physical or stored material changes are proposed for this tank, but the annual throughput of renewable feed to Tank #303 will increase due to the MaxSAF® Project and therefore, potential VOC emissions from this tank will increase. As such, a BACT analysis is being conducted for this tank.

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-12** below and the details are presented in the subsequent sections.

Table III-12
Proposed BACT Limits: Storage Tank #303 (Renewable Feed)

Emissions Unit	Pollutant	Control Technology/Practice
Existing Tank #303	VOC	Vertical fixed roof with submerged fill

Volatile Organic Compounds

The emissions mechanisms for the storage tank include 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 #303 is not/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 #303.

- 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
Please see the Definition Section XV herein for a discussion of this technology.

IFR Storage Tank
Please see the Definition Section XVI3 herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 #302.

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 is 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; and
- 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 and Document Results
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 approximately $1,250,000 – $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 0.58 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 approximately $1,250,000 – $2,000,000, which is not cost effective in consideration of the 0.58 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 0.58 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 0.58 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.

Fixed Roof Storage Tank with Submerged Fill

Fixed roof with submerged fill is an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that the original BACT analysis and determination, i.e., fixed roof with submerged fill, still represents the maximum air pollution control capacity for the VOC emissions from Tank #303. No physical modifications will be made to this tank or its existing control technology.

Existing Renewable Product Storage Tank 304

Tank #304 is an existing external floating roof (EFR) storage tank storing a VOC-containing material. The tank will experience an increase in the throughput of renewable naphtha due to the MaxSAF® Project and therefore, there will be an emissions increase from this tank as part of the Project. As such, a BACT analysis is being conducted for this tank.

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-13** below and the details are presented in the subsequent sections.

Table III-13
Proposed BACT Limits: Storage Tank #304 (Renewable Naphtha)

Emissions Unit	Pollutant	Control Technology/Practice
Existing Tank #304	VOC	Vertical external floating roof tank, 40 CFR 60 Subpart Kb

Volatile Organic Compounds

The emissions mechanisms for the storage tank include 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 #304 is subject to an NSPS Subpart Kb.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for Tank #304.

- 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
Please see the Definition Section XV herein for a discussion of this technology.

IFR Storage Tank
Please see the Definition Section XVI3 herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 #304.

IFR Storage Tank with Vapor Collection System and Control Device
This option is technically infeasible 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 an integral component of the base design and operation of the tank. Therefore, this option is technically feasible for the tank.

Fixed Roof Storage Tank with Submerged Fill
This option is technically feasible for the tank, but Tank #304 is already equipped with a more effective EFR. Therefore, this option will not be further evaluated.

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; and
- EFR Storage Tank.

Step 4: Evaluate Most Effective Control Options and Document Results
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 approximately $1,250,000 to $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 4.01 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 approximately $1,250,000 to $2,000,000, which is not cost effective in consideration of the 4.01 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 4.01 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
Tank #304 is an EFR storage tank. This control technology has been incorporated in its basic design and operation of this tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that the original BACT analysis and determination, i.e., EFR storage tank, still represents the maximum air pollution control capacity for the VOC emissions from Tank #304. No physical modifications will be made to this tank or its existing control technology.

Existing Renewable Product Storage Tank 305
Tank #305 is an existing atmospheric fixed roof storage tank storing RD. As presented above in the application materials, MRL proposes to use Tank #305 for storage of a renewable fuel product with a vapor pressure equal to or less than the vapor pressure of renewable kerosene/SAF. Potential VOC emissions from this tank have been conservatively updated based on storing renewable kerosene/SAF, which has the highest vapor pressure amount of the fuel products that may be potentially stored in this tank. No physical modifications will be made to this tank.

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-14** below and the details are presented in the subsequent sections.

Table III-14
Proposed BACT Limits: Storage Tank #305

Emissions Unit	Pollutant	Control Technology/Practice
Existing Tank #305	VOC	Vertical fixed roof with submerged fill

Volatile Organic Compounds

The emissions mechanisms for the storage tank include 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 is not subject to an NSPS or NESHAP VOC emission standard.

Step 1: Identify Control Technologies

The following are available VOC emission control technologies for Tank #305.

- 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
Please see the Definition Section XV herein for a discussion of this technology.

IFR Storage Tank
Please see the Definition Section XVI3 herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 #305.

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 is 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; and
- 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 and Document Results
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 approximately $1,250,000 to $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 7.94 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 approximately $1,250,000 to $2,000,000, which is not cost effective in consideration of the 7.94 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 7.94 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 7.94 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.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill is an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that the original BACT analysis and determination, i.e., fixed roof with submerged fill, still represents the maximum air pollution control capacity for the VOC emissions from Tank #305. No physical modifications will be made to this tank or its existing control technology.

Existing Renewable Product Storage Tank 306

Tank #306 is an existing atmospheric fixed roof storage tank storing renewable kerosene/SAF. As presented above in the application materials, MRL proposes to use Tank #306 for storage of a renewable fuel product with a vapor pressure equal to or less than the vapor pressure of renewable kerosene/SAF. Potential VOC emissions from this tank have been conservatively updated based on storing renewable kerosene/SAF, which has the highest vapor pressure amount of the fuel products that may be potentially stored in this tank, and the updated annual throughput. No physical modifications will be made to this tank.

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-15** below and the details are presented in the subsequent sections.

Table III-15
Proposed BACT Limits: Storage Tank #306

Emissions Unit	Pollutant	Control Technology/Practice
Existing Tank #306	VOC	Vertical fixed roof with submerged fill

Volatile Organic Compounds

The emissions mechanisms for the storage tank include 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 is not 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.

- 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
Please see the Definition Section XV herein for a discussion of this technology.

IFR Storage Tank
Please see the Definition Section XVI3 herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 #306.

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 is 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; and
- 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 and Document Results
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 approximately $1,250,000 to $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 1.52 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 approximately $1,250,000 to $2,000,000, which is not cost effective in consideration of the 1.52 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 1.52 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 1.52 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.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill is an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that the original BACT analysis and determination, i.e., fixed roof with submerged fill, still represents the maximum air pollution control capacity for the VOC emissions from Tank #306. No physical modifications will be made to this tank or its existing control technology.

Existing Renewable Product Storage Tank 307

Tank #307 is an existing atmospheric fixed roof storage tank storing renewable kerosene/SAF. As presented above in the application materials, MRL proposes to use Tank #307 for storage of a renewable fuel product with a vapor pressure equal to or less than the vapor pressure of renewable kerosene/SAF. Potential VOC emissions from this tank have been conservatively updated based on storing renewable kerosene/SAF, which has the highest vapor pressure amount of the fuel products that may be potentially stored in this tank, and the updated annual throughput. No physical modifications will be made to this tank.

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-16** below and the details are presented in the subsequent sections.

Table III-16
Proposed BACT Limits: Storage Tank #307

Emissions Unit	Pollutant	Control Technology/Practice
Existing Tank #307	VOC	Vertical fixed roof with submerged fill

Volatile Organic Compounds

The emissions mechanisms for the storage tank include 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 is not 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
Please see the Definition Section XV herein for a discussion of this technology.

IFR Storage Tank
Please see the Definition Section XVI3 herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 is 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; and
- 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 and Document Results
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 approximately $1,250,000 to $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 1.52 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 approximately $1,250,000 to $2,000,000, which is not cost effective in consideration of the 1.52 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 1.52 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 1.52 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.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill is an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that the original BACT analysis and determination, i.e., fixed roof with submerged fill, still represents the maximum air pollution control capacity for the VOC emissions from Tank #307. No physical modifications will be made to this tank or its existing control technology.

Existing Renewable Product Storage Tank 308

Tank #308 is an existing atmospheric fixed roof storage tank storing renewable kerosene/SAF. As presented above in the application materials, MRL proposes to use Tank #308 for storage of a renewable fuel product with a vapor pressure equal to or less than the vapor pressure of renewable kerosene/SAF. Potential VOC emissions from this tank have been conservatively updated based on storing renewable kerosene/SAF, which has the highest vapor pressure amount of the fuel products that may be potentially stored in this tank, and the updated annual throughput. No physical modifications will be made to this tank.

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-17** below and the details are presented in the subsequent sections.

Table III-17
Proposed BACT Limits: Storage Tank #308

Emissions Unit	Pollutant	Control Technology/Practice
Existing Tank #308	VOC	Vertical fixed roof with submerged filling

Volatile Organic Compounds
The emissions mechanisms for the storage tank include 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 is not 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
Please see the Definition Section XV herein for a discussion of this technology.

IFR Storage Tank
Please see the Definition Section XVI3 herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 is 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; and
- 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 and Document Results
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 approximately $1,250,000 to $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 2.18 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 approximately $1,250,000 to $2,000,000, which is not cost effective in consideration of the 2.18 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 2.18 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 2.18 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.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill is an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that the original BACT analysis and determination, i.e., fixed roof with submerged fill, still represents the maximum air pollution control capacity for the VOC emissions from Tank #308. No physical modifications will be made to this tank or its existing control technology.

New Renewable Product Storage Tank 309
The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-18** below, and the details are presented in the subsequent sections.

Table III-18
Proposed BACT Limits: Storage Tank #309

Emissions Unit	Pollutant	Control Technology/Practice
New Tank #309	VOC	Vertical fixed roof with submerged filling

Volatile Organic Compounds

Tank #309 will be an atmospheric fixed roof storage tank storing a VOC-containing material with a vapor pressure equal to or less than the vapor pressure of renewable kerosene/SAF. 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
Please see the Definition Section XV herein for a discussion of this technology.

IFR Storage Tank
Please see the Definition Section XVI herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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; and
- 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 and Document Results
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 approximately $1,250,000 to $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 1.93 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 approximately $1,250,000 to $2,000,000, which is not cost effective in consideration of the 1.93 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 1.93 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 1.93 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.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill will be an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability

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.

New Renewable Product Storage Tank 310

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-19** below, and the details are presented in the subsequent sections.

Table III-19
Proposed BACT Limits: Storage Tank #310

Emissions Unit	Pollutant	Control Technology/Practice
New Tank #310	VOC	Vertical fixed roof with submerged filling

Volatile Organic Compounds

Tank #310 will be an atmospheric fixed roof storage tank storing a VOC-containing material with a vapor pressure equal to or less than the vapor pressure of renewable kerosene/SAF. 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 #310.

- 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
Please see the Definition Section XV herein for a discussion of this technology.

IFR Storage Tank
Please see the Definition Section XVI3 herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 #310.

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; and

- 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 and Document Results
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 approximately $1,250,000 to $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 7.94 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 approximately $1,250,000 to $2,000,000, which is not cost effective in consideration of the 7.94 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 7.94 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 7.94 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.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill will be an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that a fixed roof with submerged fill represents the maximum air pollution control capability for the VOC emissions from Tank #310. Therefore, MRL will control VOC emissions from the tank by equipping it with a fixed roof and submerged fill design.

New Renewable Product Storage Tank 311
The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-20** below, and the details are presented in the subsequent sections.

Table III-20
Proposed BACT Limits: Storage Tank #311

Emissions Unit	Pollutant	Control Technology/Practice
New Tank #311	VOC	Vertical fixed roof with submerged filling

Volatile Organic Compounds

Tank #311 will be an atmospheric fixed roof storage tank storing a VOC-containing material with a vapor pressure equal to or less than the vapor pressure of renewable kerosene/SAF. 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 #311.

- 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device

Please see the Definition Section XV herein for a discussion of this technology.

IFR Storage Tank
Please see the Definition Section XVI3 herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 #311.

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; and
- 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 and Document Results
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 approximately $1,250,000 to $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 7.94 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 approximately $1,250,000 to $2,000,000, which is not cost effective in consideration of the 7.94 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 7.94 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 7.94 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.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill will be an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability

MRL determined that a fixed roof with submerged fill represents the maximum air pollution control capability for the VOC emissions from Tank #311. Therefore, MRL will control VOC emissions from the tank by equipping it with a fixed roof and submerged fill design.

New Renewable Feed Storage Tank 312

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-21** below, and the details are presented in the subsequent sections.

Table III-21
Proposed BACT Limits: Storage Tank #312 (Renewable Feed)

Emissions Unit	Pollutant	Control Technology/Practice
New Tank #312	VOC	Vertical fixed roof with submerged filling

Volatile Organic Compounds

Tank #312 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 #312.

- 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
Please see the Definition Section XV herein for a discussion of this technology.

IFR Storage Tank
Please see the Definition Section XVI herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 #312.

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; and
- 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 and Document Results
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 approximately $1,250,000 to $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The

estimate for capital cost includes the piping and a thermal oxidizer. 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 0.54 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 approximately $1,250,000 to $2,000,000, which is not cost effective in consideration of the 0.54 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 0.54 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 0.54 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.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill will be an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that a fixed roof with submerged fill represents the maximum air pollution control capability for the VOC emissions from Tank #312. Therefore, MRL will control VOC emissions from the tank by equipping it with a fixed roof and submerged fill design.

New Renewable Feed Storage Tank 313

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-22** below, and the details are presented in the subsequent sections.

Table III-22
Proposed BACT Limits: Storage Tank #313 (Renewable Feed)

Emissions Unit	Pollutant	Control Technology/Practice
New Tank #313	VOC	Vertical fixed roof with submerged filling

Volatile Organic Compounds

Tank #313 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 #313.

- 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
Please see the Definition Section XV herein for a discussion of this technology.

IFR Storage Tank
Please see the Definition Section XVI3 herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 #313.

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; and
- 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 and Document Results
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 approximately $1,250,000 to $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 0.55 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 approximately $1,250,000 to $2,000,000, which is not cost effective in consideration of the 0.55 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 0.55 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 0.55 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.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill will be an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that a fixed roof with submerged fill represents the maximum air pollution control capability for the VOC emissions from Tank #313. Therefore, MRL will control VOC emissions from the tank by equipping it with a fixed roof and submerged fill design.

New Renewable Feed Storage Tank 314

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-23** below, and the details are presented in the subsequent sections.

Table III-23
Proposed BACT Limits: Storage Tank #314 (Renewable Feed)

Emissions Unit	Pollutant	Control Technology/Practice
New Tank #314	VOC	Vertical fixed roof with submerged filling

Volatile Organic Compounds

Tank #314 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 #314.

- 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; and
- 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 the Definition Section XIV herein for a discussion of this technology.

Fixed Roof Storage Tank with Vapor Collection System and Control Device
Please see the Definition Section XV herein for a discussion of this technology.

IFR Storage Tank
Please see the Definition Section XVI3 herein for a discussion of this technology.

EFR Storage Tank
Please see the Definition Section XVII herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 #314.

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; and
- 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 and Document Results

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 approximately $1,250,000 to $2,000,000 to install piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the IFR tank's VOC emissions. It should be noted that 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. The estimate for capital cost includes the piping and a thermal oxidizer. 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 0.55 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 approximately $1,250,000 to $2,000,000, which is not cost effective in consideration of the 0.55 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 0.55 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 0.55 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.

Fixed Roof Storage Tank with Submerged Fill
Fixed roof with submerged fill will be an integral component of the design and operation of the tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that a fixed roof with submerged fill represents the maximum air pollution control capability for the VOC emissions from Tank #314. Therefore, MRL will control VOC emissions from the tank by equipping it with a fixed roof and submerged fill design.

Existing Wastewater Tank (#4201)
The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-24** below, and the details are presented in the subsequent sections.

Table III-24
Proposed BACT Limits: Existing Storage Tank #4201 (PTU Wastewater)

Emissions Unit	Pollutant	Control Technology/Practice
Existing Tank #4201	VOC	Vertical fixed roof with a Carbon Adsorption Device

Volatile Organic Compounds

Tank #4201 is an atmospheric fixed roof storage tank storing PTU wastewater potentially containing VOC. The annual PTU wastewater throughput to the tank is expected to increase due to the MaxSAF expansion project, which will increase the potential VOC emissions from the tank. As such, a BACT analysis is conducted for the tank.

Tank #4201 is not and 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; and
- 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 the Definition Section XV herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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; and
- Fixed Roof Storage Tank with Submerged Fill.

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

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that the original BACT analysis and determination, i.e., vertical fixed roof with a carbon adsorption device, still represents the maximum air pollution control capacity for the VOC emissions from Tank #4201. No physical modifications will be made to this tank or its existing control technology.

New Wastewater Tank (#4202)
The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-25** below, and the details are presented in the subsequent sections.

Table III-25
Proposed BACT Limits: Storage Tank #4202 (Wastewater)

Emissions Unit	Pollutant	Control Technology/Practice
New Tank #4202	VOC	Vertical fixed roof with a vapor collection system and control device

Volatile Organic Compounds

Tank #4202 will be an atmospheric fixed roof storage tank storing wastewater (potentially containing VOC) generated from the proposed new Water Conservation Unit. 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 #4202 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 #4202.

- Fixed Roof Storage Tank with Vapor Collection System and Control Device; and
- Fixed Roof Storage Tank with Submerged Fill.

Below, these technologies are generally described.

A floating roof is generally not an available technology for Tank #4202 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 the Definition Section XV herein for a discussion of this technology.

Fixed Roof Storage Tank with Submerged Fill
Please see the Definition Section XVIII herein 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 #4202.

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; and
- Fixed Roof Storage Tank with Submerged Fill.

Step 4: Evaluate Most Effective Control Options and Document Results
MRL will install and operate the most effective control technology on Tank #4202. Therefore, it is not necessary to analyze control technology options for the tank.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that a fixed roof with a vapor collection system and control device represents the maximum air pollution control capability for the VOC emissions from Tank #4202. Therefore, MRL will control VOC emissions from the tank by equipping it with a fixed roof and a vapor collection system and control device.

New Hot Oil Expansion Tank (D-4204)

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-26** below, and the details are presented in the subsequent sections.

Table III-26
Proposed BACT Limits: New Hot Oil Expansion Tank #D-4204 (Therminol)

Emissions Unit	Pollutant	Control Technology/Practice
New Tank #D-4204	VOC	Proper design and operation

Volatile Organic Compounds

Similar to the existing Hot Oil Tank D-4203, the new Hot Oil Expansion Tank D-4204 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-4204).

- Thermal Oxidation;
- Catalytic Oxidation;
- Absorption;
- Carbon Adsorption;
- Condensation; and
- Proper Equipment Design and Operating Practices.

Below, the available technologies are generally described.

Thermal Oxidation

Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation

Please see the Definition Section III herein 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 crossflow 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 MRL 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-4204) 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.

Adsorption
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-4204) 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 and Document Results
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 new Hot Oil Expansion Tank (D-4204), MRL concluded that it would not be cost effective to install and operate 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 NO_x and CO_2, 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 Maximum Air Pollution Control Capability
MRL determined that proper equipment design and operating practices represents the maximum air pollution control capability for VOC emissions from the new Hot Oil Expansion Tank (D-4204). Therefore, MRL will control VOC emissions from D-4204 by properly designing and operating the process vessel.

Existing Loading Operations – Renewable Diesel, Kerosene and SAF
The maximum air pollution control capability determination made for the existing truck and rail loading of renewable diesel and renewable kerosene/SAF products pursuant to ARM 17.8.752 is summarized in **Table III-27** below, and the details are presented in the subsequent sections.

Table III-27
Proposed BACT Limits: Existing Truck and Rail Loading (Renewable Diesel, Kerosene, and SAF)

Emissions Unit	Pollutant	Control Technology/Practice
Existing Truck and Rail Loading of Renewable Diesel, Kerosene and SAF	VOC	Submerged Fill

Volatile Organic Compounds

The loading activity represents the loading of renewable diesel, kerosene or SAF into tanker trucks or railcars which will have the potential to result in VOC emissions to the atmosphere because of the displacement of VOC-containing vapor present in the vessel. Due to the MaxSAF expansion project, the annual production of renewable fuel products will increase and therefore, the annual throughput to the existing truck and rail loading will increase, which will result in an increase in VOC emissions from loading. As such, a BACT analysis is conducted for the existing truck and rail loading of renewable diesel, kerosene and SAF.

The Loading - Renewable Diesel, Kerosene and SAF activity is not and 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 Operations – Renewable Fuels.

- Thermal Oxidation;
- Catalytic Oxidation;
- Absorption;
- Carbon Adsorption;
- Condensation; and
- Submerged Fill Loading.

Below, these technologies are generally described.

Thermal Oxidation
Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation
Please see the Definition Section III herein for a discussion of this technology.

Absorption (Wet Scrubber)
Please see the Definition Section XIX herein for a discussion of this technology.

Carbon Adsorption
Please see the Definition Section XX herein for a discussion of this technology.

Condensation
Please see the Definition Section II herein for a discussion of this technology.

Submerged Fill Loading
Please see the Definition Section XXIIII 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 Operations – Renewable Fuels 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 loading of renewable diesel, kerosene and SAF products 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 and Document Results
As noted above, the available add-on VOC emission control technologies are all effectively the same with respect to VOC emission control capabilities (depending on the composition of the VOC stream, these add-on controls are capable of achieving 70-80% control of VOC emissions).

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 VOC emissions from loading operation would have a capital cost of approximately $1,250,000 to $2,000,000, which is not expected to be cost effective in consideration of the maximum 17.77 tpy VOC emission rate calculated for the activity (worst-case). The estimate for capital cost includes the piping, thermal oxidizer and associated components. Additionally, annual operating costs (e.g., fuel, electricity, maintenance labor and maintenance materials) required to operate and maintain the addon control technology would make it even less cost-effective. Other add-on control devices like catalytic oxidation, condensers, wet scrubbers are expected to have the same level of capital expenditure.

Therefore, based on economic considerations, MRL eliminated add-on vapor collection system and control device from consideration as the maximum air pollution control capability for the activity's VOC emissions.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that submerged fill loading represents the maximum air pollution control capability for the VOC emissions from the truck and rail loading of renewable diesel, kerosene and SAF. MRL will continue to control VOC emissions from loading of renewable diesel, kerosene and SAF by utilizing submerged fill.

New Loading Operation – Blended SAF
The maximum air pollution control capability determination made for the new truck and rail loading of blended SAF products pursuant to ARM 17.8.752 is summarized in **Table III-28** below, and the details are presented in the subsequent sections.

Table III-28
Proposed BACT Limits: New Truck and Rail Loading (Blended SAF)

Emissions Unit	Pollutant	Control Technology/Practice
New Truck and Rail Loading of Blended SAF (from new Tank #309)	VOC	Submerged Fill

Volatile Organic Compounds

The loading activity represents the loading of blended SAF from the proposed new Tank #309 into tanker trucks or railcars which will have the potential to result in VOC emissions to the atmosphere because of the displacement of VOC-containing vapor present in the vessel. The new loading 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 operations – blended SAF.

- Thermal Oxidation;
- Catalytic Oxidation;

- Absorption;
- Carbon Adsorption;
- Condensation; and
- Submerged Fill Loading.

Below, these technologies are generally described.

Thermal Oxidation
Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation
Please see the Definition Section III herein for a discussion of this technology.

Absorption (Wet Scrubber)
Please see the Definition Section XIX herein for a discussion of this technology.

Carbon Adsorption
Please see the Definition Section XX herein for a discussion of this technology.

Condensation
Please see the Definition Section XXI herein for a discussion of this technology.

Submerged Fill Loading
Please see the Definition Section XXII 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 operations – blended SAF 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 loading of blended SAF 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 and Document Results

As noted above, the available add-on VOC emission control technologies are all effectively the same with respect to VOC emission control capabilities (depending on the composition of the VOC stream, these add-on controls are capable of achieving 70-80% control of VOC emissions).

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 VOC emissions from loading operation would have a capital cost of approximately $1,250,000 to $2,000,000, which is not expected to be cost effective in consideration of the maximum 1.20 tpy VOC emission rate calculated for the activity (worst-case). The estimate for capital cost includes the piping, thermal oxidizer and associated components. Additionally, annual operating costs (e.g., fuel, electricity, maintenance labor and maintenance materials) required to operate and maintain the addon control technology would make it even less cost-effective. Other add-on control devices like catalytic oxidation, condensers, wet scrubbers are expected to have the same level of capital expenditure.

Therefore, based on economic considerations, MRL eliminated add-on vapor collection system and control device from consideration as the maximum air pollution control capability for the activity's VOC emissions.

Step 5: Select Maximum Air Pollution Control Capability

MRL determined that submerged fill loading represents the maximum air pollution control capability for the VOC emissions from the proposed new truck and rail loading of blended SAF.

Existing Loading Operation – Renewable Naphtha

The maximum air pollution control capability determination made for the existing rail loading of renewable naphtha pursuant to ARM 17.8.752 is summarized in **Table III-29** below, and the details are presented in the subsequent sections.

Table III-29
Proposed BACT Limits: Existing Rail Loading (Renewable Naphtha)

Emissions Unit	Pollutant	Control Technology/Practice
Existing Rail Loading of Renewable Naphtha	VOC	Existing Vapor Control Unit (VCU) at CMR

Volatile Organic Compounds

The loading activity represents the existing rail loading of renewable naphtha from the existing storage Tank #304 into railcars which will have the potential to result in VOC emissions to the atmosphere because of the displacement of VOC-containing vapor present in the vessel. Due to the MaxSAF expansion project, the annual production of renewable naphtha may increase. Before the proposed Cogeneration Plant is installed and starts operation, the produced renewable naphtha will continue to be loaded out through the existing rail loading at CMR with an existing VCU for reduction of VOC emissions.

The rail loading of renewable naphtha is and will continue to be subject to NSPS Subpart Kb.

Step 1: Identify Control Technologies
The following are available VOC emission control technologies for loading of renewable naphtha.

- Thermal Oxidation;
- Catalytic Oxidation;
- Absorption;
- Carbon Adsorption;
- Condensation; and
- Submerged Fill Loading.

Below, these technologies are generally described.

Thermal Oxidation
Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation
Please see the Definition Section III herein for a discussion of this technology.

Absorption (Wet Scrubber)
Please see the Definition Section XIX herein for a discussion of this technology.

Carbon Adsorption
Please see the Definition Section XX herein for a discussion of this technology.

Condensation
Please see the Definition Section XXI herein for a discussion of this technology.

Submerged Fill Loading
Please see the Definition Section XXII 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 loading of renewable naphtha 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 loading of renewable naphtha 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 and Document Results
MRL currently utilizes the most effective control technology for loading of renewable naphtha. Therefore, it is not necessary to analyze control technology options for this process.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that the original BACT analysis and determination, i.e., routing the exhaust gases to the existing VCU at CMR, still represents the maximum air pollution control capacity for the VOC emissions from loading of renewable naphtha. No physical modifications will be made to this loading process or its existing control technology.

New Truck Loading – Heavy Fractions

The maximum air pollution control capability determination made for the new truck loading of the separated heavy fractions from the new Water Conservation Unit pursuant to ARM 17.8.752 is summarized in **Table III-30** below, and the details are presented in the subsequent sections.

Table III-30
Proposed BACT Limits: New Truck Loading of Heavy Fractions from New Water Conservation Unit

Emissions Unit	Pollutant	Control Technology/Practice
New Truck Loading of Heavy Fractions from the New Water Conservation Unit	VOC	Submerged Fill

Volatile Organic Compounds

The separated heavy fractions water from the feed centrifugal separation will be loaded out by truck for off-site disposal. The separated heavy fractions water may potentially contain a small amount of VOC, which may result in VOC emissions to the atmosphere because of the displacement of VOC-containing vapor present in the vessel. The new loading 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 loading of heavy fractions from the new Water Conservation Unit.

- Thermal Oxidation;
- Catalytic Oxidation;
- Absorption;
- Carbon Adsorption;
- Condensation; and
- Submerged Fill Loading.

Below, these technologies are generally described.

Thermal Oxidation
Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation
Please see the Definition Section III herein for a discussion of this technology.

Absorption (Wet Scrubber)
Please see the Definition Section XIX herein for a discussion of this technology.

Carbon Adsorption
Please see the Definition Section XX herein for a discussion of this technology.

Condensation
Please see the Definition Section XXI herein for a discussion of this technology.

Submerged Fill Loading
Please see the Definition Section XXII 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 loading of heavy fractions from the new Water Conservation Unit 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 loading of blended SAF 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 and Document Results
As noted above, the available add-on VOC emission control technologies are all effectively the same with respect to VOC emission control capabilities (depending on the composition of the VOC stream, these add-on controls are capable of achieving 70-80% control of VOC emissions).

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 VOC emissions from loading operation would have a capital cost of approximately $1,250,000 to $2,000,000, which is not expected to be cost effective in consideration of the negligible 0.03 tpy VOC emissions calculated for the activity. The estimate for capital cost includes the piping, thermal oxidizer and associated components. Additionally, annual operating costs (e.g., fuel, electricity, maintenance labor and maintenance materials) required to operate and maintain the addon control technology would make it even less cost-effective. Other add-on control devices like catalytic oxidation, condensers, wet scrubbers are expected to have the same level of capital expenditure.

Therefore, based on economic considerations, MRL eliminated add-on vapor collection system and control device from consideration as the maximum air pollution control capability for the activity's VOC emissions.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that submerged fill loading represents the maximum air pollution control capability for the VOC emissions from the proposed new truck loading of separated heavy fractions water from the new Water Conservation Unit.

Existing Loading Operation – PTU Wastewater
The maximum air pollution control capability determination made for this loading operation pursuant to ARM 17.8.752 is summarized in **Table III-31** below, and the details are presented in the subsequent sections.

Table III-31
Proposed BACT Limits: Existing Truck and/or Rail Loading (PTU Wastewater)

Emissions Unit	Pollutant	Control Technology/Practice
Existing Truck and/or Rail Loading of PTU Wastewater	VOC	Carbon Adsorption Device

Volatile Organic Compounds

The loading activity represents the loading of PTU wastewater into tank trucks or railcars which 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. With the MaxSAF expansion project, the amount of wastewater generated from PTU is expected to increase, which will result in an increase in VOC emissions from the loading operation. As such, a BACT analysis is conducted for the PTU wastewater loading operation.

The loading operation is not and 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 Operations – PTU Wastewater.

- Thermal Oxidation;
- Catalytic Oxidation;
- Absorption;
- Carbon Adsorption;
- Condensation; and
- Submerged Fill Loading.

Below, these technologies are generally described.

Thermal Oxidation
Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation
Please see the Definition Section III herein for a discussion of this technology.

Absorption (Wet Scrubber)
Please see the Definition Section XIX herein for a discussion of this technology.

Carbon Adsorption
Please see the Definition Section XX herein for a discussion of this technology.

Condensation
Please see the Definition Section XXI herein for a discussion of this technology.

Submerged Fill Loading
Please see the Definition Section XXII 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 Operations – PTU Wastewater 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 loading of PTU wastewater 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 and Document Results
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 Operations - PTU Wastewater activity is considerably low, MRL currently utilizes a carbon adsorption control device to minimize VOC emissions from the loading activity.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that carbon adsorption represents the maximum air pollution control capability for VOC emissions from the Loading Operations - PTU Wastewater activity. Therefore, MRL will continue to control VOC emissions from the loading activity by operating the carbon adsorption control device.

Existing PTU Blowdown Drum (D-4208)

The maximum air pollution control capability determination made for this emissions unit pursuant to ARM 17.8.752 is summarized in **Table III-32** below, and the details are presented in the subsequent sections.

Table III-32
Proposed BACT Limits: Existing PTU Blowdown Drum D-4208

Emissions Unit	Pollutant	Control Technology/Practice
Existing PTU Blowdown Drum D-4208	VOC	Carbon Adsorption Device

Volatile Organic Compounds

The PTU Blowdown Drum (D-4208) periodically receives renewable feed and renewable feed-water mixtures due to PTU equipment maintenance and PTU turnaround events. VOC emissions occur due to the volatilization of organic compounds from the material handled by the vessel. Due to the MaxSAF expansion project, the amount of VOC generated from this process vessel is expected to increase. As such, a BACT analysis is conducted for D-4208.

The process vessel is not and 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; and
- Condensation.

Below, the available technologies are generally described.

Thermal Oxidation
Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation
Please see the Definition Section III herein for a discussion of this technology.

Absorption (Wet Scrubber)
Please see the Definition Section XIX herein for a discussion of this technology.

Carbon Adsorption
Please see the Definition Section XX herein for a discussion of this technology.

Condensation
Please see the Definition Section XXI herein 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 and Document Results
As noted above, the available add-on VOC emission control technologies are all effectively the same with respect to VOC emission control capabilities. MRL currently utilizes a carbon adsorption control device to minimize the vessel's VOC emissions and an economic analysis is not being performed.

Step 5: Select Maximum Air Pollution Control Capability
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 continue to route the gaseous exhausts from the vessel to the carbon adsorption control device for reduction of VOC emissions.

New PTU Wastewater Pre-treatment System
The maximum air pollution control capability determination made for this system pursuant to ARM 17.8.752 is summarized in **Table III-33** below, and the details are presented in the subsequent sections.

Table III-33
Proposed BACT Limits: New PTU Wastewater Pre-treatment System

Emissions Unit	Pollutant	Control Technology/Practice
New PTU Wastewater Pre-treatment System	VOC	Proper design and operation

Volatile Organic Compounds

MRL proposes to install a wastewater pre-treatment system, which will be potentially comprised of oil-water separation, dissolved air flotation (DAF), coagulation, neutralization, flocculation, clarification, and aerobic digestion processes. The wastewater generated from the existing PTU and the new Water Conservation Unit will be sent to the wastewater pre-treatment system prior to being discharged to the city sewer. VOC emissions will occur due to the volatilization of organic compounds from the wastewater handled by the pre-treatment system.

This wastewater pre-treatment system 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 proposed wastewater pre-treatment system.

- Thermal Oxidation;
- Catalytic Oxidation;
- Absorption;
- Carbon Adsorption;
- Condensation; and
- Proper System Design and Operating Practices.

Below, the available technologies are generally described.

Thermal Oxidation
Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation
Please see the Definition Section III herein for a discussion of this technology.

Absorption (Wet Scrubber)
Please see the Definition Section XIX herein for a discussion of this technology.

Carbon Adsorption
Please see the Definition Section XX herein for a discussion of this technology.

Condensation
Please see the Definition Section XXI herein for a discussion of this technology.

Proper System Design and Operating Practices
The system will be properly designed and operated to minimize volatilization of organic compounds. Therefore, the amount of VOC emissions from the system will be low.

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 wastewater pre-treatment system.

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.

Proper System Design and Operating Practices
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 wastewater pre-treatment system 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 and Document Results
As noted above, the available add-on VOC emission control technologies are all effectively the same with respect to VOC emission control capabilities (depending on the composition of the VOC stream, these add-on controls are capable of achieving 70-80% control of VOC emissions).

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).

The modeled maximum VOC emissions from the proposed wastewater pre-treatment system using EPA's ToxChem Modeling Software are approximately 2.2 tpy based on MRL's existing worst-case PTU wastewater characteristics. For a conservative estimate of the potential VOC emissions from the proposed pre-treatment system, the modeled VOC emissions are doubled as provided in the permit application (4.5 tpy). MRL estimated that the installation of piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the VOC emissions from the wastewater pretreatment system would have a capital cost of approximately $1,250,000 to $2,000,000, which is not expected to be cost effective in consideration of the 4.5 tpy VOC emissions calculated for the system. The estimate for capital cost includes the piping, thermal oxidizer and associated components. Additionally, annual operating costs (e.g., fuel, electricity, maintenance labor and maintenance materials) required to operate and maintain the addon control technology would make it even less cost-effective. Other add-on control devices like catalytic oxidation, condensers, wet scrubbers are expected to have the same level of capital expenditure.

Therefore, based on economic considerations, MRL eliminated add-on vapor collection system and control device from consideration as the maximum air pollution control capability for the activity's VOC emissions.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that proper system design and operating practices represents the maximum air pollution control capability for VOC emissions from the proposed new PTU wastewater pre-treatment system. Therefore, MRL will control VOC emissions from the new PTU wastewater pre-treatment system by properly designing and operating the system.

New RFU Stripped Sour Water Recycling

The maximum air pollution control capability determination made for this process pursuant to ARM 17.8.752 is summarized in **Table III-34** below, and the details are presented in the subsequent sections.

Table III-34
Proposed BACT Limits: New RFU Stripped Sour Water Recycling

Emissions Unit	Pollutant	Control Technology/Practice
New RFU Stripped Sour Water Recycling	VOC	Proper design and operation

Volatile Organic Compounds

Currently, the stripped sour water from the RFU is sent to the existing wastewater pre-treatment system at CMR for disposal. MRL proposes to recycle a portion of the stripped sour water from the RFU back to the production process. Depending on the quality of the recycled sour water, it may be sent to the upstream of the new Water Conservation Unit or the existing PTU, or it may need to first pass through the existing deaerator to remove dissolved gases contained in the recycled water prior to being sent back to the production process. When the recycled sour water passes through the deaerator, VOC emissions may occur due to the volatilization of residual organic compounds contained in the stripped source water.

The recycling of stripped source water is not expected to 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 proposed RUF stripped source water recycling.

- Thermal Oxidation;
- Catalytic Oxidation;
- Absorption;
- Carbon Adsorption;
- Condensation; and
- Proper System Design and Operating Practices.

Below, the available technologies are generally described.

Thermal Oxidation
Please see the Definition Section II herein for a discussion of this technology.

Catalytic Oxidation
Please see the Definition Section III herein for a discussion of this technology.

Absorption (Wet Scrubber)
Please see the Definition Section XIX herein for a discussion of this technology.

Carbon Adsorption
Please see the Definition Section XX herein for a discussion of this technology.

Condensation
Please see the Definition Section XXI herein for a discussion of this technology.

Proper System Design and Operating Practices
The system will be properly designed and operated to minimize volatilization of residual organic compounds. Therefore, the amount of VOC emissions from the recycled stripped source water, when it passes through the deaerator, will be low.

Step 2: Eliminate Technically Infeasible Options
Below, we evaluate the technical feasibility of the VOC emission control technologies determined to be available for the proposed RUF stripped source water recycling.

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.

Proper System Design and Operating Practices
This option is technically feasible.

Step 3: Rank Remaining Control Technologies by Control Effectiveness
The available add-on VOC emission control technologies for the proposed RUF stripped source water recycling 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 and Document Results
As noted above, the available add-on VOC emission control technologies are all effectively the same with respect to VOC emission control capabilities (depending on the composition of the VOC stream, these add-on controls are capable of achieving 70-80% control of VOC emissions).

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).

Based on the actual sour water sampling data, the estimated VOC emissions from the recycling RFU stripped sour water are approximately 1.7 tpy based on conservative assumptions that all the recycled stripped source water would pass through the deaerator and the recycling process would run 8,760 hours per year. For a highly conservative estimate of the potential VOC emissions from this proposed recycling process, the actual source water sampling data (VOC concentration in sour water) is further multiplied by a factor of 3 (tripled), resulting in potential VOC emissions of 4.93 tpy as provided in the permit application. In reality, the recycling of stripped sour water will not be a continuous process running 8,760 hours per year and not all the recycled stripped sour water would need to be de-aerated.

MRL estimated that the installation of piping, associated equipment (e.g., valves and instrumentation) and a thermal oxidizer to collect and control the VOC emissions from the proposed stripped sour water recycling would have a capital cost of approximately $1,250,000 to $2,000,000, which is not expected to be cost effective in consideration of the 4.93 tpy VOC emissions calculated for the system. The estimate for capital cost includes the piping, thermal oxidizer and associated components. Additionally, annual operating costs (e.g., fuel, electricity, maintenance labor and maintenance materials) required to operate and maintain the addon control technology would make it even less cost-effective. Other add-on control devices like catalytic oxidation, condensers, wet scrubbers are expected to have the same level of capital expenditure.

Therefore, based on economic considerations, MRL eliminated add-on vapor collection system and control device from consideration as the maximum air pollution control capability for the activity's VOC emissions.

Step 5: Select Maximum Air Pollution Control Capability
MRL determined that proper system design and operating practices represents the maximum air pollution control capability for VOC emissions from the proposed stripped sour water recycling. Therefore, MRL will control VOC emissions from the recycling process by properly designing and operating the system.

BACT conclusions prescribed under MAQP #5263-03 provide comparable controls and control cost to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

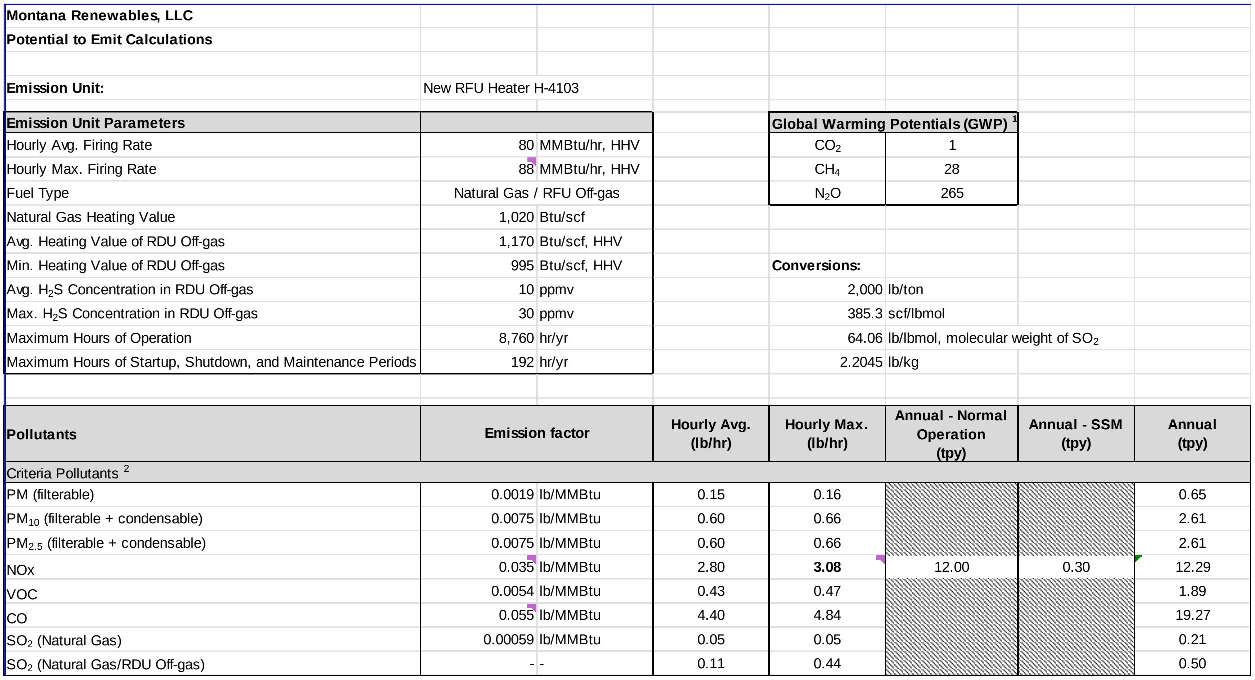
IV. Emission Inventory

The proposed emission changes occurring with this application are shown in the following table along with the potential to emit from the last issued MAQP #5263-02, as well as the resulting post-project totals following completion. The increases with this project are shown in the row titled "Project Increase".

PTE	CO	NOx	PM (filt.)	PM10	PM2.5	SO2	VOC	Max. Single (Hexane)	Total HAPs
Current Facility Wide Total	78.10	89.53	2.88	9.06	8.87	5.91	63.98	6.76	7.12
Updated Facility Wide Total with MaxSAF	168.87	149.21	10.94	37.11	36.93	20.00	153.75	13.70	17.82
Project Increase (due to MaxSAF)	90.77	59.69	8.07	28.05	28.05	14.10	89.76	6.94	10.70
MaxSAF Project Trigger PSD?	No	No	No	No	No	No	No	-	-
PSD Major Source Thresholds	100	100	-	100	100	100	100	-	-
Title V Major Source Thresholds	100	100	-	100	100	100	100	10	25

MRL will be above the PSD baseline threshold going forward and will be subject to PSD analysis if future project emission increases exceed the thresholds set for significant emission increases.

DEQ has also included the emission inventory calculations for the three new primary combustion units which would result in the main emission increases for the MaxSAF project. These are shown below as H-4103, H-5801, and for the CoGen Plant fired on both naphtha and natural gas.



Montana Renewables, LLC
Potential to Emit Calculations

Emission Unit: New RFU Heater H-4103

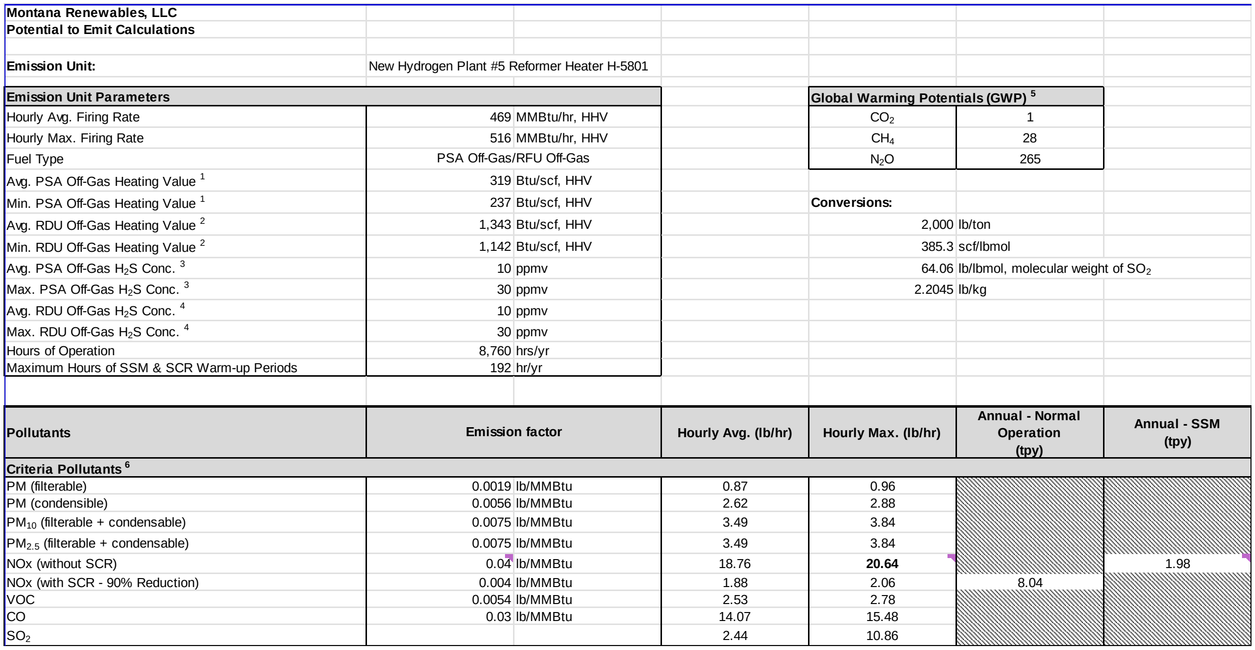
Emission Unit Parameters		
Hourly Avg. Firing Rate	80	MMBtu/hr, HHV
Hourly Max. Firing Rate	88	MMBtu/hr, HHV
Fuel Type	Natural Gas / RFU Off-gas	
Natural Gas Heating Value	1,020	Btu/scf
Avg. Heating Value of RDU Off-gas	1,170	Btu/scf, HHV
Min. Heating Value of RDU Off-gas	995	Btu/scf, HHV
Avg. H_2S Concentration in RDU Off-gas	10	ppmv
Max. H_2S Concentration in RDU Off-gas	30	ppmv
Maximum Hours of Operation	8,760	hr/yr
Maximum Hours of Startup, Shutdown, and Maintenance Periods	192	hr/yr

Global Warming Potentials (GWP) [1]	
CO_2	1
CH_4	28
N_2O	265

Conversions:

2,000	lb/ton
385.3	scf/lbmol
64.06	lb/lbmol, molecular weight of SO_2
2.2045	lb/kg

Pollutants	**Emission factor**		**Hourly Avg. (lb/hr)**	**Hourly Max. (lb/hr)**	**Annual - Normal Operation (tpy)**	**Annual - SSM (tpy)**	**Annual (tpy)**
Criteria Pollutants [2]							
PM (filterable)	0.0019	lb/MMBtu	0.15	0.16			0.65
PM_{10} (filterable + condensable)	0.0075	lb/MMBtu	0.60	0.66			2.61
$PM_{2.5}$ (filterable + condensable)	0.0075	lb/MMBtu	0.60	0.66			2.61
NOx	0.035	lb/MMBtu	2.80	**3.08**	12.00	0.30	12.29
VOC	0.0054	lb/MMBtu	0.43	0.47			1.89
CO	0.055	lb/MMBtu	4.40	4.84			19.27
SO_2 (Natural Gas)	0.00059	lb/MMBtu	0.05	0.05			0.21
SO_2 (Natural Gas/RDU Off-gas)	-	-	0.11	0.44			0.50



Montana Renewables, LLC
Potential to Emit Calculations

Emission Unit: New Hydrogen Plant #5 Reformer Heater H-5801

Emission Unit Parameters		
Hourly Avg. Firing Rate	469	MMBtu/hr, HHV
Hourly Max. Firing Rate	516	MMBtu/hr, HHV
Fuel Type	PSA Off-Gas/RFU Off-Gas	
Avg. PSA Off-Gas Heating Value [1]	319	Btu/scf, HHV
Min. PSA Off-Gas Heating Value [1]	237	Btu/scf, HHV
Avg. RDU Off-Gas Heating Value [2]	1,343	Btu/scf, HHV
Min. RDU Off-Gas Heating Value [2]	1,142	Btu/scf, HHV
Avg. PSA Off-Gas H_2S Conc. [3]	10	ppmv
Max. PSA Off-Gas H_2S Conc. [3]	30	ppmv
Avg. RDU Off-Gas H_2S Conc. [4]	10	ppmv
Max. RDU Off-Gas H_2S Conc. [4]	30	ppmv
Hours of Operation	8,760	hrs/yr
Maximum Hours of SSM & SCR Warm-up Periods	192	hr/yr

Global Warming Potentials (GWP) [5]	
CO_2	1
CH_4	28
N_2O	265

Conversions:

2,000	lb/ton
385.3	scf/lbmol
64.06	lb/lbmol, molecular weight of SO_2
2.2045	lb/kg

Pollutants	**Emission factor**		**Hourly Avg. (lb/hr)**	**Hourly Max. (lb/hr)**	**Annual - Normal Operation (tpy)**	**Annual - SSM (tpy)**
Criteria Pollutants [6]						
PM (filterable)	0.0019	lb/MMBtu	0.87	0.96		
PM (condensible)	0.0056	lb/MMBtu	2.62	2.88		
PM_{10} (filterable + condensable)	0.0075	lb/MMBtu	3.49	3.84		
$PM_{2.5}$ (filterable + condensable)	0.0075	lb/MMBtu	3.49	3.84		
NOx (without SCR)	0.04	lb/MMBtu	18.76	**20.64**		1.98
NOx (with SCR - 90% Reduction)	0.004	lb/MMBtu	1.88	2.06	8.04	
VOC	0.0054	lb/MMBtu	2.53	2.78		
CO	0.03	lb/MMBtu	14.07	15.48		
SO_2			2.44	10.86		

Montana Renewables, LLC
Potential to Emit Calculations

Emission Unit: New Cogen Plant (Mode 1: burning renewable naphtha)

Emission Unit Parameters		
Hourly Avg. Firing Rate - Turbine [1]	185	MMBtu/hr, HHV
Hourly Max. Firing Rate - Turbine	204	MMBtu/hr, HHV
Combined power production	20	MWe
Fuel Type	Renewable Naphtha	
Fuel Heating Value [2]	135,000	Btu/gal
Avg. Fuel Consumption [3]	8,822	lb/hr
	1,400	gal/hr (assumed based on 6.3 lb/gal)
	12,266,781	gal/yr
Avg. Sulfur Concentration	10	ppmv
Max. Sulfur Concentration	30	ppmv
Maximum Hours of Operation	8,760	hr/yr
Maximum Hours of SSM & SCR Warm-up Periods	192	hr/yr

Global Warming Potentials (GWP) [3]	
CO_2	1
CH_4	28
N_2O	265

Conversions:

2,000	lb/ton
385.3	scf/lbmol
64.06	lb/lbmol, molecular weight of SO_2
2.2045	lb/kg

Pollutants	**Emission factor**		**Hourly Avg. (lb/hr)**	**Hourly Max. (lb/hr)**	**Annual - Normal Operations (tpy)**	**Annual - SSM (tpy)**	**Annual Total (tpy)**
Criteria Pollutants [4]							
PM (filterable)	0.0043	lb/MMBtu	0.80	0.88	▨	▨	3.48
PM$_{10}$ (filterable + condensable)	0.0120	lb/MMBtu	2.22	2.44	▨	▨	9.72
PM$_{2.5}$ (filterable + condensable)	0.0120	lb/MMBtu	2.22	2.44	▨	▨	9.72
NOx (based on 78 ppm @ 15% O_2, w/o SCR) [5]	0.303	lb/MMBtu	56.07	**61.67**	▨	5.92	33.64
NOx (post-SCR control, assumed 9 ppm NOx @ 15% O_2) [5]	0.035	lb/MMBtu	6.47	7.12	27.71	▨	
VOC	0.0040	lb/MMBtu	0.74	0.81	▨	▨	3.24
CO (w/ water-steam injection for NOx, but no control for CO) [4]	0.076	lb/MMBtu	14.06	**15.47**	▨	1.48	7.51
CO (w/ water-steam injection for NOx, & 90% control for CO)	0.008	lb/MMBtu	1.41	1.55	6.02	▨	
SO_2	0.0030	lb/MMBtu	0.56	0.62	▨	▨	2.46

Montana Renewables, LLC
Potential to Emit Calculations

Emission Unit: New Cogen Plant (Mode 2: burning natural gas)

Emission Unit Parameters		
Hourly Avg. Firing Rate - Turbine [1]	185	MMBtu/hr, HHV
Hourly Max. Firing Rate - Turbine	204	MMBtu/hr, HHV
Combined power production	20	MWe
Fuel Type [2]	Natural Gas	
Fuel Heating Value	1,020	Btu/scf
Avg. Natural Gas Usage	0.18	MMScf/hr
Max. Natural Gas Usage	0.20	MMScf/hr
Annual Natural Gas Usage	1,589	MMScf/yr
Maximum Hours of Operation	8,760	hr/yr
Maximum Hours of SSM & SCR Warm-up Periods	192	hr/yr

Global Warming Potentials (GWP) [3]	
CO_2	1
CH_4	28
N_2O	265

Conversions:

2,000	lb/ton
2.2045	lb/kg

Pollutants	**Emission factor**		**Hourly Avg. (lb/hr)**	**Hourly Max. (lb/hr)**	**Annual - Normal Operations (tpy)**	**Annual - SSM (tpy)**
Criteria Pollutants [3]						
PM (filterable)	0.0019	lb/MMBtu	0.35	0.39	▨	▨
PM$_{10}$ (filterable + condensable)	0.0066	lb/MMBtu	1.22	1.34	▨	▨
PM$_{2.5}$ (filterable + condensable)	0.0066	lb/MMBtu	1.22	1.34	▨	▨
NOx (based on 78 ppm @ 15% O_2, w/o SCR) [5]	0.287	lb/MMBtu	53.14	**58.45**	▨	5.61
NOx (post-SCR control, assumed 9 ppm NOx @ 15% O_2) [5]	0.033	lb/MMBtu	6.13	6.74	26.27	▨
VOC	0.0021	lb/MMBtu	0.39	0.43	▨	▨
CO (uncontrolled) [4]	0.082	lb/MMBtu	15.17	**16.69**	▨	1.60
CO (with 90% control)	0.008	lb/MMBtu	1.52	1.67	6.50	▨
SO_2	0.0034	lb/MMBtu	0.63	0.69	▨	▨

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 emissions increases associated with this permit action are minor increases over the previously permitted levels for the MRL Great Falls Renewable Fuels Plant. Projected increases in MAQP #5263-03 are large enough to make the facility subject to a review against PSD significant emission rates on future permitting actions.

Ramboll Americas Engineering Solutions, Inc. (Ramboll) conducted air quality modeling for MRL's MaxSAF facility modification air quality permit application. This ambient air impact analysis was conducted, pursuant to the requirements of ARM 17.8.749, to demonstrate that the proposed modification would not cause or contribute to a violation of any state or federal ambient air quality standard. The proposed project is not categorized as a major PSD application.

The MaxSAF modification increases the facility-wide PTE above modeling thresholds listed in Montana's Draft Modeling Guideline for $PM_{2.5}$, NO_2, CO, and VOC and therefore warrants further analyses. As outlined in Sections 4.3 and 4.4.1 of the Modeling Guideline, a screening level significant impact analysis is often an adequate demonstration of compliance if the project-only emission increases do not exceed significant impact levels (SIL) for the applicable pollutant. Project-only emission increases were first modeled to determine if any model receptors exceeded the Class II SILs, presented in **Table VI-1**, and no receptors exceeded the SIL.

However, the Modeling Guideline clarifies that DEQ may request that all sources of emissions be modeled in cases where facility-wide modeling has not previously been conducted and approved. Due to a lack of representative modeling in the area surrounding MRL as well as a lack of previous MRL facility-wide modeling, DEQ deemed it inappropriate to conclude that the project emissions and existing facility emissions would not cumulatively cause or contribute to a violation of any NAAQS or MAAQS. Thus, DEQ requested that a full impact analysis inclusive of nearby sources and background concentrations be performed for $PM_{2.5}$ and NO_2, as informed by preliminary results provided by MRL and Ramboll.

MRL demonstrated compliance with all applicable NAAQS and MAAQS, presented in **Table VI-1**. Additionally, compliance was shown for the only applicable Class II Increment.

Table VI-1
Applicable standards

Pollutant	Averaging Period	Class II SIL ($\mu g/m^3$)	Primary NAAQS ($\mu g/m^3$)	MAAQS ($\mu g/m^3$)	Class II Increment ($\mu g/m^3$)
$PM_{2.5}$	24-hour	1.2	35	-	NA
	Annual	0.13	9	-	NA
NO_2	1-hour	7.5	188	564	-
	Annual	1	100	94	25
CO	1-hour	2,000	40,000	26,000	-
	8-hour	500	10,000	10,000	-
O_3(1)	8-hour	1.96	137	-	-

(1)triggered due to increase in VOC PTE

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

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

Regulatory default options were used for all model runs. Rural dispersion coefficients were applied, as all of Montana currently meets this criterion. All buildings at the site were evaluated for building downwash on each modeled point source, using BPIPPRM. For the NO_2 modeling analyses, Tier 2 (Ambient Ratio Method, ARM2) was employed in AERMOD, with the EPA default minimum and maximum ambient ratios of 0.5 and 0.9, respectively (ratio of NO_2/NO_x).

Five years of meteorological data (2020-2024) ready for use in AERMOD was constructed using representative surface and upper air data. Surface air data was obtained from the closest National Weather Service (NWS) station, which is located approximately 4 miles to the southwest of the project site at the Great Falls International Airport (KGTF – WBAN 24143). This NWS station also provided the automated surface observing system (ASOS) one-minute data used with AERMINUTE. Additionally, the upper air station in Great Falls (USM00072776) was used for upper air data. The ADJ_U* option was employed during meteorological processing in AERMET to account for stable, low wind speeds.

A series of nested receptor grids were used in the model to calculate the ambient air impacts around the project location. The MRL facility is located within a boundary shared with CMR, though MRL is considered a distinct stationary source with a different industrial grouping code. Discrete "fence line" receptors were placed at 50 m spacing along the CMR/MRL shared ambient air boundary, 100 m spacing from the site's ambient air boundary to 1 km from the site, 250 m spacing from 1 km to 3 km from the site, 500 m spacing from 3 km to 10 km from the site, and 1 km spacing from 10 km to 20 km, totaling 3,274 receptor locations. For each pollutant SIL analysis, a high resolution 25 m spacing "hot spot" receptor grid was also used to better resolve the modeled impacts within 100 m of the maximum modeled receptor. The SIL analysis, which was performed on the project-only emissions increases, did not produce any receptors with concentrations that exceeded the applicable SILs. Thus, for the provided $PM_{2.5}$ and NO_2 full impact analysis, the full receptor grid was again used.

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

Background monitors were selected from Montana's Air Quality Monitoring Network Plan (2025), based on the closest and most representative sites with available data. The following $PM_{2.5}$ and NO_2 monitoring sites were identified for use for background concentrations. For PM2.5, the most recent complete dataset (2021-2023) from the Great Falls monitor (AQS ID: 30-013-0001) was used to calculate background design concentration. For NO_2, design values were calculated from the Lewistown monitor (AQS ID: 30-027-0006), as it's the nearest NO2 monitoring site and features a similar airshed to Great Falls. The background concentrations presented in **Table VI-2** were added to the modeled concentrations in the full impact (i.e., cumulative) NAAQS/MAAQS analysis.

Table VI-2
Applicable Background concentrations

Pollutant	Averaging Time	Background Conc. (μg/m^3)	Basis	Site (AQS ID)
$PM_{2.5}$	24-hour	13.4(1)	24-hour 98th %-ile (3-yr avg)	Great Falls(2) (30-013-0001)
	Annual	6.3(1)	3-year Annual avg	
NO_2	1-hour	18.8	1-hour 98th %-ile (3-yr avg)	Lewistown(3) (30-027-0006)
	Annual	1.5	Annual avg	

(1)Data excludes all wildfire atypical event data in the calculations.
(2)Data years 2021-2023
(3)Data years 2022-2024 for 1-hour; 2024 average for annual

Onsite source parameters were provided by MRL. All were modeled as "point" sources in AERMOD, and their descriptions are displayed in **Table VI-3**.

Table VI-3
Onsite Source Descriptions

Source ID	Source Description	Source Category	Source Type
H4103	RFU Heater	New Source	POINT
H5801	H2 Plant #5 Reformer Heater	New Source	POINT
COGEN	Cogen Turbine	New Source	POINT
FLARE1/FLARE1M(1)	Flare 1	Modified Source	POINT
FLARE2/FLARE2M(1)	Flare 2	Modified Source	POINT

(1)The model ID for the project emissions from the flares in the cumulative modeling was distinguished with an "M" to represent MaxSAF

Class II SIL Air Quality Analysis

Initial modeling was performed to identify the significance of the MaxSAF project emission increases. The affected emitting units are expected to vary by load, so MRL evaluated the impacts of emission rates at 50%, 75%, and 100% load. For the SIL analysis and subsequent analyses, the 100% load emission rates are conservatively used. The new and modified sources were modeled at their hourly peak potential emissions for short term (1-hr, 8-hr, and 24-hr) averaging periods, and their annual emissions for the annual averaging periods, based on 8,760 operating hours. The emission rates resulting from the proposed MaxSAF project are listed in **Table VI-4**.

Table VI-4
SIL Modeled Emissions Increases

Source ID	$PM_{2.5}$ 24-hr (lb/hr)	$PM_{2.5}$ Annual (tpy)	NO_2 1-hr (lb/hr)	NO_2 Annual (tpy)	CO 1-hr & 8-hr (lb/hr)
H4103	0.66	2.61	3.08	12.31	4.84
H5801	3.84	15.30	1.87	10.01	15.48
COGEN	2.44	9.73	7.12	34.24	1.67
FLARE1	3.21	0.34	34.29	3.86	19.05
FLARE2	0.51	0.07	3.43	0.66	1.99
Annual Total:		**28.05**		**61.08**	

Modeled $PM_{2.5}$, NO_2, and CO Class II SIL results are presented in **Table VI-5**. The results represent the maximum modeled concentration averaged over 5 years from the "hot spot" analysis that was previously described. Additionally, to address the secondary formation of $PM_{2.5}$ and ozone from NOx/SO_2 and NOx/VOC, respectively, EPA's Modeled Emission Rates for Precursors (MERPs) tool was used. Consistent with EPA's Guidance on the Development of MERPs as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program, the hypothetical stack in Cascade County with an emission rate of 500 tpy and a stack height of 90 meters was used for $PM_{2.5}$ estimations. For ozone, the same hypothetical stack was chosen, although it was only modeled with a 10-meter stack for VOC emissions.

The estimated 8-hour ozone secondary impact in parts per billion (ppb) is 0.26 (26% of the SIL). The estimated secondary impact for 24-hr and annual $PM_{2.5}$ is 0.011 $\mu g/m^3$ and 0.00033 $\mu g/m^3$, respectively. These secondary $PM_{2.5}$ concentrations are included in the reported SIL analysis results in **Table VI-5**. Because no receptors exceed the applicable SILs (accounting for secondary formation), it has been demonstrated that the MaxSAF project will not cause or contribute to a violation of a NAAQS or MAAQS.

Table VI-5
Class II Significant Impact Analysis Results

Pollutant	Avg. Period	Model Conc. ($\mu g/m^3$)	SIL ($\mu g/m^3$)	Exceed SIL?	Percent of SIL
$PM_{2.5}$(1)	24-hour(2)	0.8	1.2	No	67%
	Annual(3)	0.13	0.13	No(8)	99.7%
NO_2	1-hour(4)	7.0	7.5	No	93%
	Annual(5)	0.4	1.0	No	40%
CO	1-hour(6)	15.3	2,000	No	0.7%
	8-hour(7)	5.1	500	No	1.0%

(1)Includes secondary $PM_{2.5}$ formation.

(2)The receptor with the maximum 5-year average 24-hour concentration.

(3)The receptor with the maximum 5-year average annual concentration.

(4)The receptor with the maximum 5-year average of the maximum daily 1-hour concentration.
(5)The receptor with the maximum annual average in the 5-year period.
(6)The receptor with the maximum 1-hour concentration in the 5-year period.
(7)The receptor with the maximum 8-hour concentration in the 5-year period.
(8)Reported value was 0.1296.

NAAQS/MAAQS Air Quality Analysis

For NAAQS (i.e., cumulative full impact) and Increment analyses, all new/modified sources were modeled at their peak emissions, which are displayed in **Table VI-4**. Nearby/offsite source emissions (which includes existing MRL emissions) were also included in these analyses. All facilities within a 50 km radius of the MRL facility were considered and included in the cumulative modeling demonstrations to conservatively estimate all potential impacts. Those facilities are identified in **Table VI-6**.

Table VI-6
Nearby/Offsite Source Facility List

Facility	Distance from MRL (km)
CMR	0.00
Great Falls Wastewater Treatment Plant	0.35
MHP - Great Falls Office	1.17
Grain Craft	1.50
Croxford Funeral Home & Crematory	1.57
O'Connor Funeral Services	2.50
General Mills Operations Inc	2.72
ADF International - Montana	2.81
ADF Industrial Coatings	3.09
Great Falls Elevator	3.36
Malteurop	3.39
Hillcrest Lawn Memorial Associations	3.82
CHS Nutrition	5.75
Montana Specialty Mills - MVO	6.44
Montana Air National Guard	7.15
Malmstrom AFB	8.61
High Plains Sanitary Landfill and Recycling Center	13.90
Power Elevator	36.83
EGT LLC - Carter	43.50

For the NAAQS/MAAQS analyses, the nearby sources were modeled at either their maximum permit (MAQP) limits or actual emission rates averaged over the most recent two emission inventory years (2023-2024) in accordance with 40 CFR Part 51 Appendix W Table 8-2. For nearby sources with unknown release parameters, default conservative values were used to limit plume buoyancy and dispersion. All offsite facilities and annual emissions are shown in **Table VI-7** below. Source descriptions and AERMOD source types are shown in **Table VI-8** (includes existing MRL emission sources).

Table VI-7
Nearby/Offsite Sources Modeled Emissions

Facility	$PM_{2.5}$ (tpy)	NO_2 (tpy)
ADF Industrial Coatings	0.00	0.00
ADF International - Montana	0.00	0.00
CHS Nutrition	1.92	0.05
CMR	18.48	102.77
Croxford Funeral Home & Crematory	0.03	0.05
EGT LLC - Carter	0.63	0.00
General Mills Operations Inc	0.20	0.30
Grain Craft	4.64	0.11
Great Falls Elevator	0.00	0.00
Great Falls Wastewater Treatment Plant	0.29	3.24
High Plains Sanitary Landfill and Recycling Center	2.73	0.80
Hillcrest Lawn Memorial Associations	0.02	0.03
Malmstrom AFB	0.16	14.55
Malteurop	3.37	0.01
MHP - Great Falls Office	0.00	0.00
Montana Air National Guard	0.03	1.03
Montana Specialty Mills - MVO	0.02	2.38
O'Connor Funeral Services	0.03	0.04
Power Elevator	0.07	0.00

Table VI-8
Nearby/Offsite Source Descriptions

Source ID	Facility	Source Description	Source Type
FCCU_HTR	CMR	FCC Preheater	POINT
FCCU	CMR	FCCU	POINT
REF_HTR	CMR	Reformer Heater	POINT
NHDS_HTR	CMR	NHDS Heater	POINT
NAPH_REB	CMR	Naptha Splitter Reboiler	POINT
CR2_AHTR	CMR	Crude #2 Atmospheric Heater	POINT
CR2_VHTR	CMR	Crude #2 Vacuum Heater	POINT
DIB_HTR	CMR	DIB Reboiler Heater	POINT
HTU_HTR	CMR	HTU Heater	POINT
BLR_1_2	CMR	Boiler #1 / #2	POINT
BLR_3	CMR	Boiler #3	POINT
H2_2_HTR	CMR	#2 H2 Plant Reformer Heater	POINT
N_CWT	CMR	North Cooling Towers	POINT
S_CWT	CMR	South Cooling Towers	POINT
OIL_HTR1	CMR	Hot Oil Heater	POINTCAP

Source ID	Facility	Source Description	Source Type
RAIL_VCU	CMR	Railcar Loading VCU	POINT
TR_VCU	CMR	Truck Loading VCU	POINT
FLARE1C	CMR	Flare 1 (cumulative)	POINT
FLARE2C	CMR	Flare 2 (cumulative)	POINT
HTR_135	CMR	Tank #135 Heater	POINTCAP
HTR_137	CMR	Tank #137 Heater	POINTCAP
HTR_138	CMR	Tank #138 Heater	POINTCAP
HTR_139	CMR	Tank #139 Heater	POINTCAP
EGEN	CMR	Generator	POINTHOR
ECOMP	CMR	Air compressor	POINTCAP
SWPUMP	CMR	API Storm Water Pump	POINTCAP
FW_54	CMR	Fire Water Pump (Tank 54)	POINTCAP
FW_24	CMR	Fire Water Pump (Tank 24)	POINTHOR
FW_146	CMR	Fire Water Pump (Tank 146)	POINTCAP
DROP	CMR	PMA Handling	VOLUME
CONV1	CMR	PMA Handling	VOLUME
CONV2	CMR	PMA Handling	VOLUME
CONV3	CMR	PMA Handling	VOLUME
CONV4	CMR	PMA Handling	VOLUME
RFU_CF	MRL Existing	RFU Combined Feed Heater	POINT
RFU_FF	MRL Existing	RFU Fractionator Feed Heater	POINT
H2_3_HTR	MRL Existing	#3 H2 Plant Reformer Heaters	POINT
H2_4_HTR	MRL Existing	#4 H2 Plant Reformer Heater	POINT
OIL_HTR2	MRL Existing	Hot Oil Heater	POINT
LP_BLR1	MRL Existing	LP Boiler #1	POINTCAP
LP_BLR2	MRL Existing	LP Boiler #2	POINTCAP
GEN1	MRL Existing	Generator #1	POINT
GEN2	MRL Existing	Generator #2	POINT
NEARBY01	Malmstrom AFB	Boiler #1	POINT
NEARBY02	Malmstrom AFB	Boiler #2	POINT
NEARBY03	Malmstrom AFB	Boiler #3	POINT
NEARBY04	CHS Nutrition	Boiler	POINT
NEARBY05	CHS Nutrition	Grain Receiving	POINT
NEARBY06	CHS Nutrition	Grain Handling	POINT
NEARBY07	CHS Nutrition	Hammermill	POINT
NEARBY08	CHS Nutrition	Pellet Mill #1	POINT
NEARBY09	CHS Nutrition	Bulk Loadout	POINT
NEARBY10	CHS Nutrition	Storage Bins	POINT

Source ID	Facility	Source Description	Source Type
NEARBY11	CHS Nutrition	Pellet Mill #2	POINT
NEARBY12	CHS Nutrition	Natural Gas Boiler	POINT
NEARBY13	CHS Nutrition	Steam Rolling	POINT
NEARBY14	General Mills Operations Inc	Large Boiler	POINT
NEARBY15	General Mills Operations Inc	Small Boiler	POINT
NEARBY16	General Mills Operations Inc	Railcar Receiving	POINT
NEARBY17	General Mills Operations Inc	Combined Fugitives	POINT
NEARBY18	Great Falls Elevator	Combined Fugitives	POINT
NEARBY19	Grain Craft	Boiler	POINT
NEARBY20	Montana Air National Guard	Boilers, Heaters, Furnaces	POINT
NEARBY21	Montana Air National Guard	Engine Test Cell	POINT
NEARBY22	Montana Air National Guard	Emergency Generator	POINT
NEARBY23	Montana Air National Guard	Aerospace Ground Equip	POINT
NEARBY24	Montana Air National Guard	Grit Blasting Room	POINT
NEARBY25	High Plains Sanitary Landfill and Recycling Center	Flare	POINT
NEARBY26	High Plains Sanitary Landfill and Recycling Center	Haul Roads	POINT
NEARBY27	Croxford Funeral Home & Crematory	Crematorium	POINT
NEARBY28	Malteurop	Baghouses	POINT
NEARBY29	Malteurop	Heaters	POINT
NEARBY30	Malteurop	Fugitive Emissions	POINT
NEARBY31	Malteurop	Baghouse 4	POINT
NEARBY32	Hillcrest Lawn Memorial Associations	Crematorium	POINT
NEARBY33	Great Falls Wastewater Treatment Plant	Generating Set	POINT
NEARBY34	Great Falls Wastewater Treatment Plant	Sludge Heating Boiler	POINT
NEARBY35	Great Falls Wastewater Treatment Plant	Heating Boiler	POINT
NEARBY36	Great Falls Wastewater Treatment Plant	Emergency Generator	POINT
NEARBY37	Great Falls Wastewater Treatment Plant	Waste Gas Burner	POINT
NEARBY38	EGT LLC - Carter	Grain Receiving	POINT
NEARBY39	EGT LLC - Carter	Head House	POINT
NEARBY40	EGT LLC - Carter	Storage Bins	POINT
NEARBY41	EGT LLC - Carter	Rail Loadout	POINT
NEARBY42	EGT LLC - Carter	Truck Loadout	POINT
NEARBY43	EGT LLC - Carter	Road Traffic	POINT
NEARBY44	Power Elevator	Grain Receiving	POINT
NEARBY45	Power Elevator	Internal Grain Handling	POINT
NEARBY46	Power Elevator	Grain Storage	POINT

Source ID	Facility	Source Description	Source Type
NEARBY47	Power Elevator	Grain Shipping	POINT
NEARBY48	Power Elevator	Haul Roads	POINT
NEARBY49	ADF International - Montana	Steel Fabrication Plant	POINT
NEARBY50	ADF International - Montana	Natural Gas Cutting Torch	POINT
NEARBY51	ADF Industiral Coatings	Wheelobrator	POINT
NEARBY52	ADF Industiral Coatings	IBT Steel Shot Blast Booth	POINT
NEARBY53	ADF Industiral Coatings	Paint Booth	POINT
NEARBY54	ADF Industiral Coatings	Fico Plasma Cutting Torch	POINT
NEARBY55	ADF Industiral Coatings	Gemini Plasma Cutting Torch	POINT
NEARBY56	MHP - Great Falls Office	Firelake Model P16-SC4	POINT
NEARBY57	Montana Specialty Mills - MVO	Storage Bins	POINT
NEARBY58	Montana Specialty Mills - MVO	Weight Hopper/Handling	POINT
NEARBY59	Montana Specialty Mills - MVO	Cleaning	POINT
NEARBY60	Montana Specialty Mills - MVO	Screening	POINT
NEARBY61	Montana Specialty Mills - MVO	Low Pressure Boiler	POINT
NEARBY62	Montana Specialty Mills - MVO	Hammerhouse/Handling	POINT
NEARBY63	O'Connor Funeral Services	Crematorium	POINT
NRBYV01	Grain Craft	Truck Unloading	VOLUME
NRBYV02	Grain Craft	Railcar Unloading	VOLUME
NRBYV03	Grain Craft	Cleaning House	VOLUME
NRBYV04	Grain Craft	Hammermill	VOLUME
NRBYV05	Grain Craft	Feeding Grinders	VOLUME
NRBYV06	Grain Craft	Roll Stand Grinders	VOLUME
NRBYV07	Grain Craft	Sifters/Bulk Flour Bins	VOLUME
NRBYV08	Grain Craft	Hammermill in Flour Mill	VOLUME
NRBYV09	Grain Craft	Railcar & Truck Bulk Loadout	VOLUME
NRBYV10	Grain Craft	Collection Bin - Millruns	VOLUME
NRBYV11	Grain Craft	Loadout Mill Runs to Railcar	VOLUME

The results of the NAAQS analyses are shown in **Table VI-9** and **Table VI-10** below. The absolute maximum modeled impacts inclusive of all nearby sources within 50 km and background concentrations are shown to be in compliance with the NO_2 1-hour and annual NAAQS. The $PM_{2.5}$ maximum modeled impacts are in excess of both the 24-hour and annual NAAQS, however, this does not indicate that the MaxSAF project nor the MRL facility as a whole will cause or contribute to a violation of the NAAQS.

Table VI-10 lists all 3 of the modeled $PM_{2.5}$ NAAQS violations and identifies the relative contribution of the MaxSAF project and MRL (inclusive of MaxSAF) at the time and location of each exceedance. In accordance with EPA's Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program, SILs may be used in a cumulative modeling demonstration to identify whether the applicant facility is "culpable" in the event of a modeled NAAQS violation. As discussed in the 2024 Supplement to the Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program (EPA), because the $PM_{2.5}$ SIL values are set based on the range of intrinsic variability in ambient air observations, modeled impacts that are less than the SIL (even in a cumulative NAAQS analysis) are considered statistically insignificant. Therefore, in similar fashion to the use of SILs in a screening-level capacity, if the modeled impacts from the applicant facility is less than that of the applicable SIL at the violating receptor location (and time, for short term averaging periods), then it has been demonstrated that the facility will not cause or contribute to a violation of the NAAQS.

Further, an analysis of the location of the modeled NAAQS violations reveals that they occur at two facilities that were modeled using combined fugitive $PM_{2.5}$ sources and very conservative release parameters due to uncertainties in their permit histories and time constraints while developing the modeling emission inventory. It's likely that combining the fugitive sources at each facility to individual release points caused a large overprediction of ambient air impacts, and when the data are plotted, this is apparent by the steep concentration gradients around each nearby facility.

The results in **Table VI-10** clearly demonstrate that MRL's contribution, whether the project-level or facility-wide emissions, is insignificant during all three modeled NAAQS violations, and therefore MRL's modified facility models in compliance with the NAAQS.

Table VI-9
NAAQS Analysis Results

Pollutant	Avg. Period	Model Design Value (μg/m^3)	Monitor Design Value (μg/m^3)	Total Conc. (μg/m^3)	Primary NAAQS (μg/m^3)	% of NAAQS
$PM_{2.5}$(1)	24-hour(2)	48.3	13.4	61.7	35	176%
	Annual(3)	8.0	6.3	14.3	9	159%
NO_2	1-hour(4)	148.6	18.8	167.4	188(5)	89%
	Annual(3)	21.4	1.5	22.9	100(6)	23%

(1)Includes secondarily formed $PM_{2.5}$ impacts.

(2)The receptor with the 8th-highest 24-hr concentration per year, averaged over 5 years.

(3)The receptor with the maximum annual concentration averaged over 5 years.

(4)The receptor with the 8th-highest daily 1-hr max concentration averaged over 5 years.

(5)Results indicate compliance with the MAAQS (564 μg/m3)

(6)Results indicate compliance with the MAAQS (94 μg/m3)

Table VI-10
Modeled Impacts Above the NAAQS

Pollutant	Avg. Period	SIL ($\mu g/m^3$)	MRL Contribution ($\mu g/m^3$)	MaxSAF Contribution ($\mu g/m^3$)	Cumulative Impact ($\mu g/m^3$)	Location (UTM Coords)
$PM_{2.5}$	24-hour	1.2	0.03	0.02	61.7	[479001.73, 5262569.20]
	Annual	0.13	0.02	0.01	14.3	[479001.73, 5262569.20]
			0.07	0.04	10.2	[480251.73, 5265819.20]

Class II Increment Air Quality Analysis

The MRL facility is not considered a PSD-major facility under the current permit action. However, the minor-source baseline date for NOx was triggered for Cascade County on February 22, 1993 with the submittal of Calumet Montana Refining's complete application for MAQP #2161-06. MRL is therefore an increment-consuming source, and it was requested that a Class II increment analysis be performed.

Due to time constraints, it was conservatively assumed that all nearby sources are competing sources (i.e., increment consuming), so the emission rates for nearby/offsite sources remained the same for both the cumulative NAAQS analysis and the Class II increment analysis. The result of the increment analysis, which is equivalent to the NO_2 annual cumulative modeled impact, is presented in **Table VI-11** below.

Table VI-11
Class II Increment Analysis Results

Pollutant	Avg. Period	Model Conc. ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)	% of Increment
NO_2	Annual(2)	21.4	25	86%

(1)The receptor with the maximum second highest 24-hour concentration in the 5-year period.
(2)The receptor with the maximum annual concentration in the 5-year period.

Class I Air Quality Analysis

Though not explicitly required for minor NSR sources, a Class I air quality analysis was performed due to MRL's proximity within 100 km to the nearest Class I area. The closest federally mandated Class I Area is the Gates of the Mountains Wilderness area, which is 75 km southwest. DEQ evaluated air quality impacts utilizing a Q/d analysis, which is generally requested by federal land managers when a Class I Area is greater than 50 km from the project site. The emissions (Q) is the sum of SO_2 (21.29 tpy), NO_x (182.66 tpy), PM_{10} (37.27 tpy), and H_2SO_4 (0 tpy), and the distance (d, in kilometers) is the distance from the project site to the Class I Area. The Q/d results are displayed in **Table VI-12** for the three nearest Class I Areas. Q/d less than 10 is generally where federal land managers consider the impacts at the Class I Area as negligible.

Table VI-12
Class I Q/d Analysis Results

Class I Area	Distance (km)	Q/d
Gates of the Mountains Wilderness	75	3.22
Scapegoat Wilderness	97	2.49
Bob Marshall Wilderness	106	2.28

DEQ determined that the project related PM_{10}, $PM_{2.5}$, NO_2, and CO emissions (with offsite facility emissions) will not cause or contribute to a violation of a federal or state ambient air quality standard. This decision was based on the air dispersion modeling with qualitative/quantitative analyses. The full modeling analysis submitted with the MAQP application is on file with DEQ.

VII. Private Property Impacts

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

YES	NO	
		questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

The proposed project would take place on private land. DEQ has determined that the permit conditions are reasonably necessary to ensure compliance with applicable requirements under the Montana Clean Air Act. Therefore, DEQ's approval of MAQP #5263-03 would not have private property-taking or damaging implications.

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: November 7, 2025

FINAL ENVIRONMENTAL ASSESSMENT

December 15, 2025

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

PROJECT/SITE NAME: Great Falls Renewables Diesel Plant- MaxSAF™

APPLICANT/COMPANY NAME: Montana Renewables, LLC

MONTANA AIR QUALITY PERMIT #5263-03

LOCATION: Section 1, Township 20 North, Range 3 East in Cascade County

PROPERTY OWNERSHIP: FEDERAL STATE PRIVATE ✕

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OVERVIEW OF PROPOSED ACTION

Authorizing Action

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

DEQ incorporates by reference previous EA's which have been conducted for this site as this project continues the expansion of renewable fuel production at the site. Potential impacts for this project are similar to impacts identified previously related to renewable fuels production. Previous EA's for this project were associated with MAQP #5263-00, #5263-01 and #5263-02. These permits and their associated EAs remain available on DEQ's website.

Permits and associated EA's are linked here:
MAQP #5263-00: https://deq.mt.gov/files/Air/AirQuality/Documents/ARMpermits/5263-00.pdf
MAQP #5263-01: https://deq.mt.gov/files/Air/AirQuality/Documents/ARMpermits/5263-01.pdf
MAQP #5263-02: https://deq.mt.gov/files/Air/AirQuality/Documents/ARMpermits/5263-02.pdf

MAQP #5263-00, Permit final on October 26, 2021, EA final on October 8, 2021.
MAQP #5263-01, Permit final on July 7, 2022, EA Final on June 21, 2022.
MAQP #5263-02, Permit final on November 9, 2023, EA Final on October 24, 2023.

Description of DEQ Regulatory Oversight

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

Proposed Action

Montana Renewables, LLC (MRL) has applied for a Montana Air Quality Permit (MAQP) modification under the CAA. The MAQP regulates the Great Falls Renewables Fuel Plant. This proposed expansion would increase MRL's combined sustainable aviation fuel (SAF) and renewable diesel (RD) production capacity from the current 16,140 barrels per day (bpd) capacity to 24,000 bpd on an annual average, with a daily maximum of 27,000 bpd. The project is herein referred to as the "MaxSAF™ Project".

The MaxSAF™ Project include additions of an additional renewable fuel unit (RFU) reactor, a new RFU heater, a new hydrogen plant (#5), a Water Conservation Unit associated with the existing pretreatment unit (PTU), several new storage tanks, a new rail/truck loadout for blended SAF, an on-site PTU wastewater pre-treatment system, associated piping systems, and a cogeneration plant. DEQ may not approve a proposed project contained in an application for an air quality permit unless the project complies with the requirements set forth in the CAA of Montana and the administrative rules adopted thereunder, ARMs 17.8.101 et. seq. The proposed action would be located on privately owned land, in Cascade County, Montana. All information included in this EA is derived from the permit application, discussions with the applicant, analysis of aerial photography, topographic maps, Environmental Assessments incorporated by reference as stated above, and other research tools.

There are also administrative actions requested within the same MAQP application. These include removal of any Consent Decree (CD) (CIV-no 01-142LH) limits and removal of any plantwide limits which DEQ has determined are not applicable to MRL. The removal of these administrative limits is not subject to review under MEPA.

Table 2. Summary of Proposed Action

General Overview	**The action is for an increase in production from the current 16,140 barrels per day (bpd) capacity to 24,000 bpd for sustainable aviation fuel and renewable diesel. In order to achieve the increased production, the following new equipment would be constructed.** • **Additional renewable fuel unit (RFU) reactor** • **A new RFU heater (H-4103)** • **A new Hydrogen Plant with new Reformer Heater (H-5801)** • **A Water Conservation Unit associated with the existing pretreatment unit (PTU)** • **Several new storage tanks including** o **Three (3) renewable feed storage tanks** o **Three (3) renewable kerosene/SAF storage tanks** • **Switch Tank Service for six (6) existing tanks** • **A new rail/truck loadout arm for blended SAF** • **An on-site PTU wastewater pre-treatment system including a new wastewater storage tank** • **Cogeneration Plant with 20 MW Turbine** • **Associated piping systems**
Duration & Hours of Operation	**Construction:** **Construction for the proposed action would occur in stages to accommodate maintaining the existing facility operation while installing and bringing new and modified process equipment on-line. The total project duration may last as long as four years.** **Operation:** **There would be no change in operation hours for the facility, as the current facility generally operates 24/7. Any new equipment would be expected to operate on a near continuous basis.**
Estimated Disturbance	**There would be no new first-time disturbance as the project would occur within the existing boundary of a historical industrial site. The application has identified that 3 to 5 acres of land that would be re-purposed for the project.**
Construction Equipment	**Typical construction equipment, including cranes, earth moving equipment (bulldozer, grader, frontend loader, trackhoe) forklifts, telehandlers, boring and drilling rigs.**
Personnel Onsite	**Construction: Approximately 350 contractors during the peak construction period.** **Operation: Up to 40 permanent new staff would be anticipated.**
Location and Analysis Area	**Location: The facility location is for latitude 47.522981, and longitude -111.295454 This parcel is located within Section 1 of Township 20 North, Range 03 East.** **Analysis Area: The area being analyzed as part of this environmental review includes the immediate project area (Figure 1), as well as neighboring lands surrounding the analysis area, as reasonably appropriate for the impacts being considered.**

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

Air Quality	**Cascade County is designated as unclassified/attainment area.**
Water Quality	**This permitting action would not affect water quality. MRL is required to comply with the applicable local, county, state and federal requirements pertaining to water quality.**
Erosion Control and Sediment Transport	**This permitting action would not affect erosion control and sediment transport. MRL is required to comply with the applicable local, county, state and federal requirements pertaining to erosion control and sediment transport. During construction, storm water prevention best practices would be employed to mitigate run-off.**
Solid Waste	**This permitting action would not affect solid waste in the area. MRL is required to comply with the applicable local, county, state and federal requirements pertaining to solid waste.**
Cultural Resources	**This permitting action would not affect cultural resources. MRL is required to comply with the applicable local, county, state and federal requirements pertaining to cultural resources. This Proposed Action is on private land and any cultural resources discovered on the site would be the private landowner's property.**
Hazardous Substances	**This permitting action would not contribute to any hazardous substances. MRL is required to comply with the applicable local, county, state and federal requirements pertaining to hazardous substances.**
Reclamation	**This permitting action would not require any reclamation.**

Table 3. Cumulative Impacts

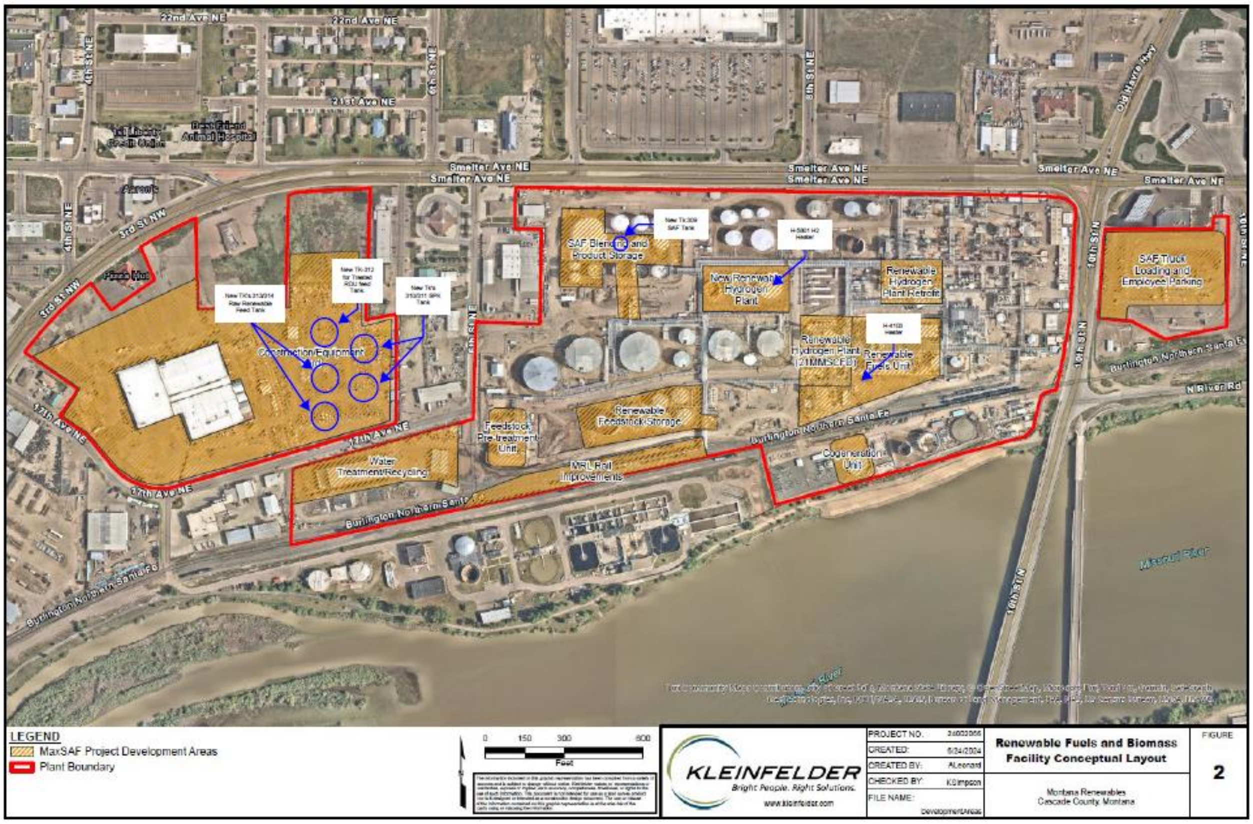
Past Actions	**MRL was first issued a permit in October 2021. This project is similar to the previous three permit actions in that each project continues to expand and develop the site for production of renewable fuels products. The original MAQP #5263-00 is most similar to the current proposed project.**
Present Actions	**This permitting action increases the annual average daily production barrel equivalent from approximately 16,140 barrels per day (bpd) capacity to 24,000 bpd.**
Related Future Actions	**MRL has not applied for or have any other applications under concurrent review by any other agencies for this facility. Future projects requiring a state permit would be subject to a new permit application. DEQ is not aware of other planned actions that would be subject to DEQ review in the area of the facility.**

Purpose, Need, and Benefits

DEQ's purpose in conducting this environmental review is to act upon MRL's application for a MAQP to expand capacity of the existing renewable fuels products. DEQ's action on the permit application is governed by § 75-2-201, et seq., Montana Code Annotated (MCA) and the Administrative Rules of Montana (ARM) 17.8.740, et seq.

The applicant's purpose and need, as expressed to DEQ in seeking this action, is to increase the throughput of sustainable aviation fuel and renewable diesel from 16,140 bbl/day to 24,000 bbl/day.

Figure 1. General Location of the Proposed Project



Other Governmental Agencies and Programs with Jurisdiction

The proposed action would be located on private land owned by the applicant. The proposed action would mostly remain within the 44.46 acre legal parcel where much of the MRL and Calumet Montana Refinery operate. However, the proposed project would also include siting within additional parcels that are also owned by Calumet Montana Refining, LLC. The upper left polygon is a part of an approximate 16.24 acre parcel, the upper right polygon is approximately a 7.21 acre parcel, and the lower right portion below the railroad line is approximately a 3.1 acre parcel. All of the land within the proposed project area was previously analyzed by the State Historical Preservation Office (SHPO) as the search area for SHPO was conducted for Section 1 Township 20N Range 3E, which encompasses the current proposed footprint. . However, the previous MTNHP search was only conducted for the 44.46 acre parcel, so a new search was carried out to address a soils search as well as a new MTNHP search. All applicable local, state, and federal rules must be adhered to, which may include other local, state, federal, or tribal agency jurisdiction. Other governmental agencies which may have overlapped, or additional jurisdiction include but may not be limited to: City of Great Falls, Cascade County Weed Control Board, OSHA (worker safety), DEQ AQB (air quality) and DEQ Water Protection Bureau for groundwater, surface water discharge and stormwater.

EVALUATION OF AFFECTED ENVIRONMENT AND IMPACT BY RESOURCE

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

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

The duration of the proposed action is quantified as follows:

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

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

The intensity of the impacts is measured using the following:

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

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

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

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

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

1. Geology and Soil Quality, Stability and Moisture

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

Affected Environment

The proposed action increases the throughput of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production.

The affected area is primarily an industrial complex historically part of the Calumet Petroleum refinery, and now more recently, part of the existing MRL renewable fuels facility which began operation in 2021. The Geology and Soil Quality, Stability and Moisture were previously evaluated under permitting actions MAQP #5263-00, MAQP #5263-01 and MAQP #5263-02. The resource area remains consistent with the earlier analyses and are incorporated from the previously conducted EAs. A new soils search was done specific for MAQP #5263-03 using the NRCS USDA website. A polygon specific to the Calumet Montana Refining, LLC parcels was created to match the area of interest for the project. The resulting survey finds that the majority of the classification is Kobar-Marias complex, zero to 4 percent slopes with 71 percent within this category. The next largest classification is Marias silty clay, 2 to 4 percent slope at 16.7 percent, the third largest classification is Kobar silty clay loam, zero to 2 percent slopes at 8.8 percent. The small soil category remaining is Kobar silty clay loam at 2 to 4 percent slopes. *Link is: https://websoilsurvey.nrcs.usda.gov/app/WebSoilSurvey.aspx*

The site is located on the north-side of the Missouri River on Montana Renewables property adjacent to the river. The parcel for the newest MRL equipment is located approximately 100 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 Layer identified as "Parcels" which has a topographic elevation marked very close to the Burlington Northern Santa Fe railway track. The ArcGIS layer link is identified as:
https://gisservicemt.gov/arcgis/rest/services/MSDI_Framework/Parcels/MapServer/0

The Montana Renewables facility 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 MRI – 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 semiconfined conditions.

Direct Impacts

Proposed Action: There would be no direct construction or operational impacts to geology, soil quality, stability, or moisture as a result of the project. The current site is an already developed renewable fuels production facility with no first-time ground disturbances.

Secondary Impacts

Proposed Action: There would be no secondary construction or operational impacts to geology or soil quality, stability, and moisture. The current site is an already developed renewable fuels production facility with no first-time ground disturbances.

Cumulative Impacts

Proposed Action: There would be no cumulative impacts to geology or soil quality, stability, and moisture. The current site is an already developed petroleum refinery with no first-time ground disturbances.

2. Water Quality, Quantity, And Distribution

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

Affected Environment

This project would not impact any surface or groundwater in the area. The Missouri River is approximately 100 feet to the south from the newest proposed equipment. No wetlands have been identified on the site. All work would be conducted within the boundary of the existing site which hosts both the Calumet Refinery and the existing Montana Renewables facility.

Direct Impacts

Proposed Action: As part of the project, MRL proposes to install both a water conservation unit and a new PTU wastewater treatment system which would provide improved handling of water within the renewables plant. This treatment plant would be expected to reduce the planned flow to the city POTW along with a more consistent concentration of species in the wastewater. Based on this information, DEQ anticipates an overall beneficial impact on water quality, quantity, and distribution with the on-site upgrades.

A new wastewater storage tank would be installed, adding capacity to the existing storage tank already onsite, and wastewater would either be discharged to the new PTU Wastewater Treatment system or hauled off-site for disposal.

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. No direct construction or operational impacts to water quality, quantity, and distribution would be expected as a result of the proposed action during construction. 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

Proposed Action: No secondary construction or operational impacts to water quality, quantity, or distribution would be expected. The current site is an already developed renewable fuels production facility.

Cumulative Impacts

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

3. Air Quality

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

Affected Environment

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 is a “chemical process plant”, which is one of the 28 source categories. Therefore, the PSD major source threshold for the plant is 100 tpy. Once the project is complete, MRL would exceed the 100 TPY threshold, thus establishing the plant as a PSD (ARM 17.8.8 Prevention of Significant Deterioration of Air Quality) source. This would trigger future permit actions to be evaluated for significant net emission increases per the definition found at ARM 17.8.8(28)(a). 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. Existing sources of air pollution in the area include emissions from the Calumet Refinery, the existing MRL operations, as well as five smaller sources holding Montana Air Quality Permits. Facilities within a 1.5-mile radius of MRL, include the Great Falls Wastewater Treatment Plant (MAQP #4176-00), Montana Highway Patrol Incinerator (MAQP #5174-00), Grain Craft (MAQP #2885-01), and O-Connor Funeral Crematorium (MAQP #5227-00), and Croxford Funeral Crematorium (MAQP #3032-01). As mentioned in the secondary impacts section below, additional nearby sources of emissions were also specifically modeled for contributions to ambient air quality.

The proposed action increases the renewable fuels annual production from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Potential emission increases associated with the project are shown along with the current potential to emit for the same pollutants. The highest level of increases would be associated with NOx and VOCs, respectively each with potential increases of each near 90 tpy. Potential NOx increases are just below 60 tpy. Other increases are as shown. MRL would exceed major source thresholds for a single HAP as it would be above the 10 tpy threshold. However, MRL is major for additional pollutants already requiring a Title V Operating Permit.

PTE	CO	NOx	PM (filt.)	PM10	PM2.5	SO2	VOC	Max. Single (Hexane)	Total HAPs
Current Facility Wide Total	78.10	89.53	2.88	9.06	8.87	5.91	63.98	6.76	7.12
Updated Facility Wide Total with MaxSAF	168.87	149.21	10.94	37.11	36.93	20.00	153.75	13.70	17.82
Project Increase (due to MaxSAF)	90.77	59.69	8.07	28.05	28.05	14.10	89.76	6.94	10.70
MaxSAF Project Trigger PSD?	No	No	No	No	No	No	No	-	-
PSD Major Source Thresholds	100	100	-	100	100	100	100	-	-
Title V Major Source Thresholds	100	100	-	100	100	100	100	10	25

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

In addition, MAQP #5263-03 provides legally enforceable conditions regarding the new emitting units, modified emitting units, pollution controls, and requires the applicant to take reasonable precautions to limit fugitive dust from this location.

Direct Impacts:

Proposed Action: Emission increases associated with the project as described above, would primarily be associated with the new emitting units combusting fuels resulting in the direct release of pollutants including CO, NOx, PM, VOCs and SO_2. Modeling submitted by MRL required by DEQ in order to make the application complete, has demonstrated that the proposed project would not be expected to cause or contribute to a violation of the applicable NAAQS for any regulated pollutant. As described in the Ambient Air Quality Impacts Section of the Air Quality Permit Analysis; details on air quality modeling are described. The duration of the combustion emissions would long-term. The proposed emission increases would be mitigated by implementation of enforceable limits, conditions, and reasonable precautions. Enforceable limits would largely be mitigated through the incorporation of Best Available Control Technology (BACT) analyses as included within the MAQP.

Under the proposed action, startup, shutdown and maintenance (SSM) NOx limits were incorporated for existing heaters, the new heaters and Cogeneration Plant. These limits become the applicable emission limits during non-steady state operation. The definition for non-steady state operation are defined with the permit in Section IV. During these SSM periods, slightly elevated NOx emission limits are provided to accommodate instances such as lack of effective pollution controls because the necessary process conditions are not possible during these periods. The SSM periods also account for metal heat-ups times that are required to avoid metal fatigue. The SSM annual periods are monitored to confirm that the number of occurrences and total duration are not beyond the assumptions used to develop the facility emission inventory. NOx emissions during the SSM periods would be considered negligible occurring for durations tracked in hours but are longterm in that they would be present as long as the facility operates the respective heaters and Cogeneration plant.

Adverse air quality impacts would be minor because of the proposed project. See permit analysis for more information regarding air quality impacts.

Secondary Impacts:

Proposed Action: Emissions from the proposed project would use the established BACT limits located in Section II of the permit above for the new and modified emitting units, and would not be expected to cause or contribute to a violation of the health and welfare-based primary and secondary NAAQS. As described in the Ambient Air Quality Impacts Section of the Air Quality Permit Analysis; results on air quality modeling are described and briefly summarized here. DEQ's Modeling Guideline clarifies that DEQ may request that all sources of emissions be modeled in cases where facility-wide modeling has not previously been conducted and approved. Due to a lack of representative modeling in the area surrounding MRL as well as a lack of previous MRL facility-wide modeling, DEQ deemed it inappropriate to conclude that the project emissions and existing facility emissions would not cumulatively cause or contribute to a violation of any NAAQS or MAAQS. Thus, DEQ requested that a full impact analysis inclusive of nearby sources and background concentrations be performed for $PM_{2.5}$ and NO_2. The results indicated that on three occasions at two unique receptor locations; one for the $PM_{2.5}$ 24-hour standard and two for the $PM_{2.5}$ Annual standard, that there may be NAAQS violations at these two locations. While MRL $PM_{2.5}$ emissions may reach the three receptor locations, the significant impact analysis demonstration shows MRL will not cause or contribute to a violation of the NAAQS at these three receptors. Read the full Ambient Air Quality Impact Section for a full explanation of the analysis.

The submitted modeling demonstration provides assurance that the proposed emission levels would not result in impacts. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings.

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

Cumulative Impacts:

Proposed Action: Cumulative impacts from the increase in bbl/day are restricted by conditions and limits contained in the MAQP; therefore, any expected air quality impacts would be minor. The Cascade County area also has one other, similar stationary source, the Calumet Montana Refinery that also contributes to the overall air quality effectively at the same site, as they each operate on the same land parcel. The cumulative impacts of the Calumet Montana Refinery and the proposed action would have a minor adverse impact to air quality. Impacts from the Permitting Action are limited by enforceable conditions and limits contained in the MAQP and BACT limits incorporated.

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

4. Vegetation Cover, Quantity, and Quality

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

Affected Environment

The affected area is primarily of industrial land within the city of Great Falls.

The proposed action increases the throughput of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production.

Direct Impacts:

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

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 petroleum refinery (Calumet) was first issued in 1985. The Department earlier conducted research for MAQP #5263-00 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 Calumet/Montana Renewables site in an urban and industrial setting where the vegetation is limited.

Secondary Impacts:

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

Cumulative Impacts:

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

5. Terrestrial, Avian, and Aquatic Life and Habitats

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

Affected Environment

The affected area is primarily industrial land within the city of Great Falls.

The proposed action increases the throughput of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production.

Direct Impacts:

Proposed Action: As described earlier in Section 4. Vegetation Cover, the larger polygon area is represented by commercial and industrial operations and the Department conducted research for MAQP #5263-00 using the Montana Natural Heritage Program (MTNHP) website and ran the query titled "Environmental Summary Report" dated August 24, 2021. 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 proposed project due to the Missouri River.

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

Secondary Impacts:

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

Cumulative Impacts:

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

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

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

Affected Environment

DEQ earlier conducted a search using the Montana Natural Heritage Program (MTNHP) site for the original 44.46 acre parcel. To accommodate the expanded footprint for this action, a new MTNHP Environmental Summary report was downloaded on October 9, 2025. The default polygons for the selected area includes area into and across the Missouri River with the default polygons totaling approximately two square miles (1280 acres). The physical changes to the facility would accommodate the throughput increase of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production.

Species of concern (SOC) from the new MTNHP report identified the following species: Great Blue Heron, Common Tern, Spiny softshell, Forster's Tern, American White Pelican, Black-crowned Night Heron, White-faced ibis, Caspian Tern, Barrow's Goldeneye, Black-necked Stilt, Sharp-tailed Grouse, Black Tern, Ferruginous Hawk, Horned Grebe, American Goshawk, Cassin's Finch, Brewer's Sparrow, Franklin's Gull, Clark's Grebe, common Loon, Solitary Sandpiper, Trumpeter Swan, and Harlequin Duck. 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.

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

Direct Impacts:

Proposed Action: The majority species of concern from the MTNHP list are associated with the riverine habitat on the Missouri River, which is approximately 100 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.

No direct construction or operational impacts to unique, endangered, fragile, or limited environmental resources would be expected as a result of the proposed action.

Secondary Impacts:

Proposed Action: No secondary impacts from construction or operations are expected as a result of the proposed project. The affected area is an already developed industrial facility with no terrestrial, avian, or aquatic habitats located within the property boundary.

Cumulative Impacts:

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

7. Historical and Archaeological Sites

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

Affected Environment

The Montana State Historic Preservation Office (SHPO) was notified of the application for the original MAQP #5263-00. A new search was not conducted for this application given it is at the same property location. SHPO conducted a file search and provided a letter dated August 25, 2021. The SHPO searched was conducted for Section 1 T20N R3E. This proposed project does not occur outside the original search area, and is not proposed to disturb ground which has not been previously disturbed before. However, the original SHPO findings for the project area are included below.

The file search identified 19 cultural resource sites within the search area criteria.

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

Direct Impacts:

Proposed Action: Further evaluation of existing site forms 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. 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 proposed occurring within the existing industrial boundary and no new disturbance for the project, there would be no adverse effects to Historic Properties. If resources were discovered during any portion of the project, it would be MRI's responsibility to determine next steps as required by law. No direct construction or operational impacts to historical or archaeological sites would be expected as a result of the proposed action because of no new ground disturbance.

Secondary Impacts:

Proposed Action: No secondary construction or operational impacts to historical or archaeological sites would be expected as a result of the proposed action because there would be no new ground disturbance.

Cumulative Impacts:

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

8. Aesthetics

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

Affected Environment

Physical changes to the facility would accommodate the throughput increase of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production. The new and modified equipment would contribute to additional equipment, potentially with additional noise and changes to the visual view of the industrial site. Some of the new stacks would be as tall as existing structures located at MRL and the adjacent CMR site.

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, and to the east of the proposed SAF loading area by approximately 350 feet. As MRL infrastructure expands, other houses and residences located around the facility get closer to the industrial operations. It is not expected that the nearest residences to the proposed site would experience any noticeable change in noise levels.

Direct Impacts:

Proposed Action: 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 2026 and continuing thru the end of the project. 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.

Secondary Impacts:

Proposed Action: Long term impacts would include additional equipment on site that would have additional potential for noise and the change in visual view of the site.

Cumulative Impacts:

Proposed Action: Cumulative impacts would be limited to the additional industrial equipment that may have noise and change in the visual view.

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

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

Affected Environment

Physical changes to the facility would accommodate the throughput increase of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production. The new and modified equipment would contribute to additional equipment, potentially with additional resource demands of land, water, and energy.

Direct Impacts:

Proposed Action: During construction of the proposed action there would be minor increase of energy use to construct the proposed action. Once operational, energy and electric demands would continue for the duration of the facility’s lifetime. Renewable diesel would provide fuel for emerging markets where non-fossil fuels are preferred and or required. The MRI production capacity increase would represent a n approximate 50 percent increase above the current permitted capacity.

The proposed action increase would increase the facility demands for energy which would be considered minor and long-term. Due to the infrastructure related to water and water quality, a beneficial impact may occur for both reduction in water usage and reduction in water discharge volumes.

Secondary Impacts:

Proposed Action: Final disposition of waste products is unknown but off-site disposal of some quantity of wastewater is possible because system optimization success is unknown at this time.

Cumulative Impacts:

Proposed Action: The increase in demand for land, water and energy would add to the existing demand for the current capacity of the facility. Minor and long-term impacts would be associated with the proposed action due to the increase of energy to accommodate the 50 percent capacity increase.

10.Impacts on Other Environmental Resources

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

Affected Environment

The proposed action increases the throughput of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production.

Direct Impacts:

Proposed Action: No direct construction or operational impacts on demands of environmental resources would be expected as a result of the proposed action because the proposed action is similar in nature to the current operations of the facility.

Secondary Impacts:

Proposed Action: No secondary construction or operational impacts demands of environmental resources would be expected as a result of the proposed action because the proposed action is located at an existing similar facility.

Cumulative Impacts:

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

11.Human Health and Safety

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

Affected Environment

The proposed action increases the throughput of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production.

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Direct Impacts:

Proposed Action: No direct construction or operational impacts to human health and safety would be expected as a result of the proposed action. Emissions released into the human environment from the facility due to the proposed action would be considered minor according to Montana Air Quality Permitting Rules found at ARM 17.8.801 Definitions.

Secondary Impacts:

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

Cumulative Impacts:

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

12.Industrial, Commercial, and Agricultural Activities and Production

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

Affected Environment

The site is currently zoned heavy industrial as is reflected by the existing MRL operation and the Calumet refinery, and other industrial and commercial properties. There is no agricultural activity at the site. The proposed action increases the throughput of renewable fuel products from 16,140 bpd capacity to 24,000 bpd. Within this resource, other industrial and commercial activities related to expanded raw material usage for the proposed action, and products produced would be part of the affected environment.

Direct Impacts:

Proposed Action: Most of the rest of the existing parcel is already covered by equipment and access roads on the property. Some existing equipment infrastructure on the MRL/Calumet site may be repositioned to facilitate the necessary footprint for the proposed project. 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 long-term.

An increase in rail and truck traffic bringing in raw materials including feedstock such as canola oil would occur. Similarly, outgoing products and waste would result in in increase in out-going industrial truck and rail traffic.

Secondary Impacts:

Proposed Action: No secondary construction impacts to industrial, commercial, or agricultural activities are expected with the proposed project. However, minor operational impacts to and production would be expected as a result of the proposed action because the proposed action increases the allowed annual average throughput which may impact raw materials to the site and product shipping from the site.

Cumulative Impacts:

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

13.Quantity and Distribution of Employment

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

Affected Environment

The proposed project would require a number of construction-related employees estimated by MRL at 350. Once the project is complete, MRL estimates that a total of 350 permanent employees would be working at the site, increasing from the current number of employees by an approximately 40 employees.

Direct Impacts:

Proposed Action: The proposed project is expected to require a number of temporary construction employees, and would require an estimated 40 additional permanent staff.

Secondary Impacts:

Proposed Action: Support-related employment would potentially occur related to the delivery of raw materials to the site, and to the increased output of production from the site that would move from the site via trucking and/or railcars.

Cumulative Impacts:

Proposed Action: Overall, the project would require new employees, approximately 40 permanent jobs, to support the long-term operation of the project.

14.Local and State Tax Base and Tax Revenue

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

Affected Environment

The proposed action increases the throughput of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production. Short-term impacts for construction and long-term impacts from continuous operation would occur.

Direct Impacts:

Proposed Action: The proposed action would be expected to have minor to moderate impacts on the local and state tax base and tax revenue. Increases in raw material usage would be expected to contribute to those suppliers being paid for the raw materials. The construction project would provide approximately 350 temporary contractor jobs after which approximately 40 permanent jobs would be created.

Secondary Impacts:

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

Cumulative Impacts:

Proposed Action: Long-term beneficial minor impacts to moderate impacts s to local and state tax base and tax revenues are anticipated from this permitting action.

15.Demand for Government Services

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

Affected Environment

The proposed action increases the throughput of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production.

Direct Impacts:

Proposed Action: New equipment and/or modified equipment may require additional oversight for source testing and compliance demonstrations. This oversight may be in addition to other on-going compliance activities.

Secondary Impacts:

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

Cumulative Impacts:

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

16.Locally Adopted Environmental Plans and Goals

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

Affected Environment

A review was conducted of the City of Great Falls website on August 18, 2025, for MAQP #5263-03. A zoning map was previously reviewed for earlier permitting actions, and the proposed project would be located on an I-2 Heavy Industrial Zone parcel. Other Planning documents were also viewed one of which was a Missouri River Urban Corridor Plan (Plan). 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 indicates that the City is updating their Growth Plan Policy indicating it will include a 2024-2025 update.

The below information was taken from the Environmental Division from the City of Great Falls website and is included for additional reference.

The Environmental Division website indicates their objectives as:

- Protect and implement water quality standards.
- Oversee and implement the Industrial Pretreatment Program (IPT).
- Manage a Fats, Oil and Grease (FOG) and Trucked and Hauled Waste Sector Control Programs.
- Manage and implement the City of Great Falls Municipal Separate Storm Sewer System (MS4) Program.
- Educate the general public and consultants on environmental regulations.
- Respond to the public's environmental needs

Direct Impacts:

Proposed Action: No locally adopted environmental plans and goals were identified other than those listed above as objectives for the Environmental Division of the City of Great Falls. MRL would be responsible for any of their operations which are covered by the above objectives. Specifically, MRL would continue to haul raw materials which may be subject to the fats, oil and grease program, and likely also subject to stormwater and industrial pretreatment programs. These programs would be outside the regulatory authority established in the Air Quality Permit.

Secondary Impacts:

Proposed Action: While some planning objectives are established for the City of Great Falls, these objectives would be expected to get included as part of the normal procedures of the City of Great Falls working with area industrial businesses. Negligible to minor secondary impacts to locally adopted environmental plans and goals would be expected because of the proposed project.

Cumulative Impacts:

Proposed Action: Negligible to minor impacts to the locally adopted environmental plans and goals are anticipated because MRL would be expected to coordinate with the City of Great Falls to achieve environmental goals.

17.Access to and Quality of Recreational and Wilderness Activities

This section includes the following resource areas, as required in ARM 17.4.609: Impacts on Access to and Quality of Recreation and Wilderness Activities

Affected Environment

The proposed action increases the throughput of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production. The current site of the proposed action is in an area of heavy 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:

Proposed Action: There are no wilderness areas that occur in the vicinity of the proposed project. 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, process heaters and stacks. These recreationalists might be river rafters, fishermen and others drawn to the river. The noise would be similar in nature to the existing MRL operations and CMR Refinery. Duration would be expected to be negligible but exist on a long-term basis because exposure would be limited to the time recreationalists are directly south of the facility.

Secondary Impacts:

Proposed Action: The effected area consists primarily of industrial property. The project would have no impacts on the immediate area, therefore, no secondary impacts to access and quality of recreational and wilderness activities would be expected because of proposed facility operations.

Cumulative Impacts:

Proposed Action: No cumulative impacts to access and quality of recreational and wilderness activities are anticipated as a result of the proposed permitting action based on direct and secondary impacts.

18.Density and Distribution of Population and Housing

This section includes the following resource areas, as required in ARM 17.4.609: Impacts on Density and Distribution of Population and Housing

Affected Environment

The proposed action increases the throughput of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production.

Direct Impacts:

Proposed Action: MRL would need to employ temporary construction workers with up to 350 for the project, and also predicts the creation of 40 permanent new positions at MRL. During the construction period, it is expected that temporary housing would be available in or near Great Falls or from nearby surrounding communities. The additional permanent positions would likely continue to stress the lack of housing experienced in many locations in Montana. Therefore, negligible to minor impacts to density and distribution of population and housing would be expected because of the proposed project.

Secondary Impacts:

Proposed Action: The proposed project would likely create additional supporting jobs such as for transportation of materials and products, creating some additional need for area housing. Therefore, negligible to minor secondary impacts to density and distribution of population and housing would be expected because of the proposed project.

Cumulative Impacts:

Proposed Action: No cumulative impacts to density and distribution of population and housing are anticipated as a result of the proposed permitting. There are no impacts on the density and distribution of population and housing.

19.Social Structures and Mores

This section includes the following resource areas, as required in ARM 17.4.609: Impacts on Social Structures and Mores

Affected Environment

The proposed action increases the throughput of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production.

Direct Impacts:

Proposed Action: Construction and operation of the proposed project would not be expected to affect the existing customs and values of the affected population. Therefore, no direct impacts to the existing social structures and mores of the affected population would be expected because of the proposed project.

Secondary Impacts:

Proposed Action: No secondary impacts to social structures and mores are anticipated because of the implementation of the project.

Cumulative Impacts:

Proposed Action: No cumulative impacts to social structures and mores are anticipated because of the implementation of the project.

20.Cultural Uniqueness and Diversity

This section includes the following resource areas, as required in ARM 17.4.609: Impacts to Cultural Uniqueness and Diversity

Affected Environment

The proposed action increases the throughput of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production.

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

Direct Impacts:

Proposed Action: No impacts to cultural uniqueness and diversity are anticipated from this project because of the proposed project. Temporary construction workers from out-of-state with special skills would likely be used for the project but because of the temporary nature of their employment would not be expected to change the cultural uniqueness and diversity of the area on a long-term basis.

Secondary Impacts:

Proposed Action: No secondary impacts to cultural uniqueness and diversity are anticipated from this project.

Cumulative Impacts:

Proposed Action: No cumulative impacts to cultural uniqueness and diversity are anticipated from this project.

21. Private Property Impacts

The proposed project would take place on private land owned by the applicant. DEQ's approval of MAQP #5263-03 would affect the applicant's real property. DEQ has determined, however, that the permit conditions are reasonably necessary to ensure compliance with applicable requirements under the CAA Act. Therefore, DEQ's approval of MAQP #5263-03 would not have private property-taking or damaging implications.

22. Other Appropriate Social and Economic Circumstances

This section includes the following resource areas, as required in ARM 17.4.609: Impacts to Other Appropriate Social and Economic Circumstances

Affected Environment

The proposed action increases the throughput of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production.

Direct Impacts:

Proposed Action: The proposed action is not expected to cause any other short-term social and economic circumstances in the affected area that may be directly impacted by the proposed project. Due to the nature of the proposed action, no further direct impacts would be expected because of the proposed project.

Secondary Impacts:

Proposed Action: The proposed action is not expected to cause any other long-term social and economic circumstances in the affected area that may be impacted by the proposed project. No secondary impacts would be expected because of the proposed project.

Cumulative Impacts:

Proposed Action: No cumulative impacts to any other social and economic circumstances are anticipated because no direct and secondary impacts were identified.

23. Greenhouse Gas Assessment

Affected Environment

The analysis area for this resource is limited to the activities regulated by the issuance of MAQP #5263-03 which provides an increase in bbl/day of renewable fuels products. The GHG emissions were calculated from the project operation increase from 16,140 bbl/day to 24,000 bbl/day on an annual average.

For the purpose of this analysis, DEQ has defined greenhouse gas emissions as the following gas species: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and many species of fluorinated compounds. The range of fluorinated compounds includes numerous chemicals which are used in many household and industrial products.

Other pollutants can have some properties that also are similar to those mentioned above, but the EPA has clearly identified the species above as the primary Greenhouse Gases (GHGs). Water vapor is also technically a greenhouse gas, but its properties are controlled by the temperature and pressure within the atmosphere, and it is not considered an anthropogenic species.

Montana recently used the EPA State Inventory Tool (SIT) to develop a greenhouse gas inventory. This tool was developed by EPA to help states develop their own greenhouse gas inventories, and this relies upon data already collected by the federal government through various agencies. The inventory specifically deals with CO_2, CH_4, and N_2O and reports the total as CO_2e.

The SIT consists of eleven Excel based modules with pre-populated data that can be used as default settings or in some cases, allows states to input their own data when the state believes their own data provides a higher level of quality and accuracy.

Once each of the eleven modules is filled out, the data from each module is exported into a final "synthesis" module which summarizes all of the data into a single file. Within the synthesis file, several worksheets display the output data in a number of formats such as emissions by sector and emissions by type of greenhouse gas. The SIT data is currently updated through the year 2022, as it takes several years to validate and make new data available within revised modules. The year 2022 run and inputs selected show Montana has a GHG inventory of 51.04 million metric tons.

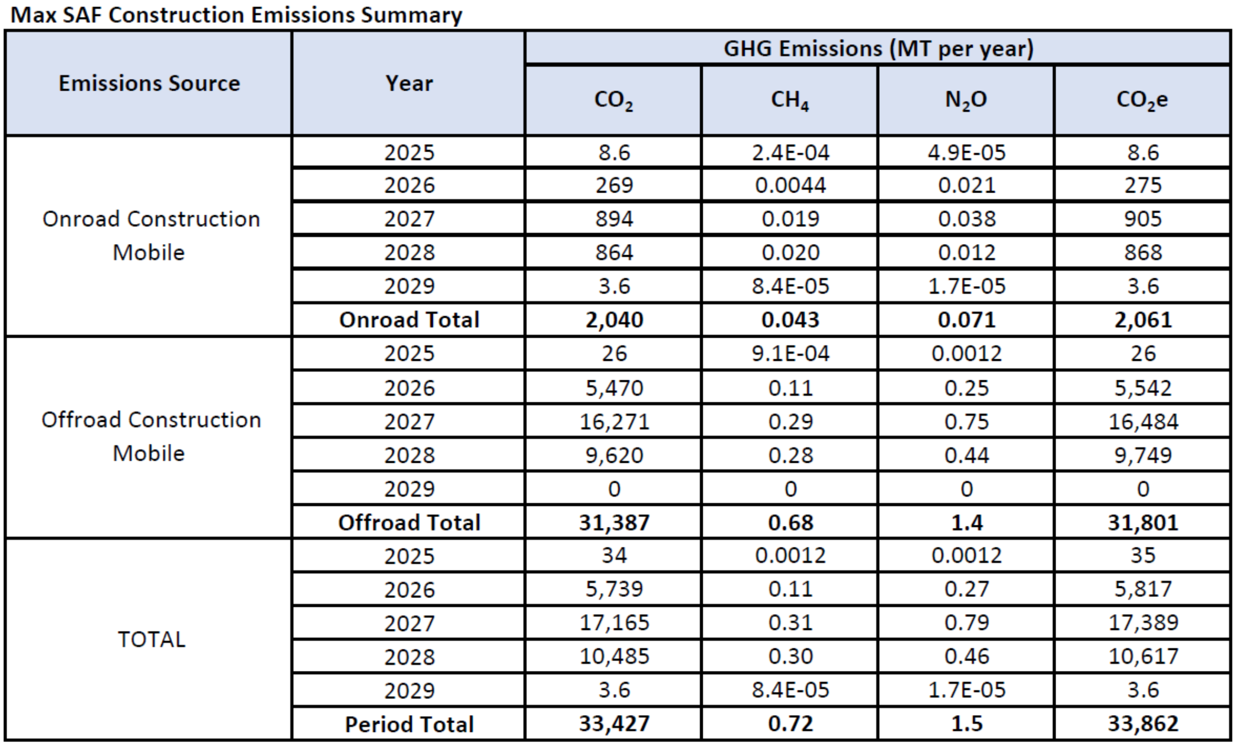
The combustion of volatile organic compounds at the site would release GHGs primarily being CO_2, N_2O, and much smaller concentrations of incomplete combustion of fuel components including CH_4 and other volatile organic compounds (VOCs).

Mobile emissions associated with this action are limited to construction of the site. This amount is estimated for the project but only expected to be within an order of magnitude of actual operational usage. Additionally, there are no known compressed gases, fire suppressants or refrigerants/air conditioning associated with this project which would have been considered Scope 1 emissions.

This review does not include an assessment of GHG impacts in quantitative economic terms, otherwise known as evaluating the social cost of carbon. DEQ instead calculates potential GHG emissions and provides a narrative description of GHG impacts. This approach is consistent with Montana Supreme Court caselaw and the agency's discussion of other impacts in this EA. See Belk v. Mont. DEQ, 2022 MT 38, ¶ 29.

MRL presented a summary of construction-related GHG emissions which would occur over the potential four-year construction schedule. Vehicle contributions are estimated from on-road vehicles and non-road construction equipment. DEQ has reviewed the submitted inventory which appears to have utilized both the EPA MOVES4 Model and the California Emissions Estimate Model for estimates which DEQ believes is equivalent to emission factors from the EPA Simplified Calculator tool. CO_2e totals are based on emission factors for CO_2, methane and nitrous oxide (N_2O). Each identified equipment type uses a horsepower and operating hour estimate (8 hrs= 1 day of operation) combined with emission factors in a gram per brake horsepower factor.

On-road vehicle estimates are identified by equipment purpose, miles traveled and grams per mile traveled to calculate on-road GHG emissions. For the four-year project duration, a total of 33,862 metrics tons of CO_2e would occur.



Max SAF Construction Emissions Summary

Emissions Source	Year	GHG Emissions (MT per year)			
		CO_2	CH_4	N_2O	CO_2e
Onroad Construction Mobile	2025	8.6	2.4E-04	4.9E-05	8.6
	2026	269	0.0044	0.021	275
	2027	894	0.019	0.038	905
	2028	864	0.020	0.012	868
	2029	3.6	8.4E-05	1.7E-05	3.6
	Onroad Total	**2,040**	**0.043**	**0.071**	**2,061**
Offroad Construction Mobile	2025	26	9.1E-04	0.0012	26
	2026	5,470	0.11	0.25	5,542
	2027	16,271	0.29	0.75	16,484
	2028	9,620	0.28	0.44	9,749
	2029	0	0	0	0
	Offroad Total	**31,387**	**0.68**	**1.4**	**31,801**
TOTAL	2025	34	0.0012	0.0012	35
	2026	5,739	0.11	0.27	5,817
	2027	17,165	0.31	0.79	17,389
	2028	10,485	0.30	0.46	10,617
	2029	3.6	8.4E-05	1.7E-05	3.6
	Period Total	**33,427**	**0.72**	**1.5**	**33,862**

MRL provided an operational-life cycle analysis for the application which DEQ chose not to incorporate as it would not be consistent with DEQ's approach or the MEPA statute to only identifying Scope 1 emissions associated for direct release of GHG emissions at the site for on-going operational GHG emissions. The MRL lifecycle analysis was separated into downstream tailpipe emissions, usage of the products and direct facility emissions during MaxSAF fuel production. The portion of the MRL submittal that was used was the category titled Fuel Production Increases-MaxSAF direct facility emissions which DEQ has reviewed and validated which was determined to be equivalent to the Scope 1 emissions approach. This totaled 556,988 metric tons of CO_2e annually for the proposed project.

Direct Impacts

Proposed Action: Construction and operation of the proposed project would utilize a significant amount of construction related vehicles which would burn diesel and gasoline for fuels. On-going operation of the project would utilize combustion of both fossil fuel-based fuels such as natural gas and would also utilize off-gases produced at the renewables facility which would be represented by short to medium chain hydrocarbons.

The construction estimate is 33,862 metric tons of CO_2e from fossil fuel combustion which would occur over an estimated 4-your project construction schedule.
The annual operational CO_2e emissions would be 556,988 metric tons.

Secondary Impacts

Proposed Action: Secondary impacts mean a further impact to the Montana environment that may be stimulated or induced by or otherwise result from a direct impact of the Proposed Action under MEPA. GHG emissions contribute to changes in atmospheric radiative forcing, resulting in climate change impacts. GHGs act to contain solar energy loss by trapping longer wave radiation emitted from the Earth's surface and act as a positive radiative forcing component (Bureau of Land Management (BLM), 2024)

A tool used to assist in the analysis of secondary climate impacts from project-level emissions is the Methods for Attributing Climate Impacts of GHG Emissions (MAGICC) (Climate Resource, 2022) model to calculate the secondary impacts of GHGs. The MAGICC model is a peer-reviewed reduced-complexity model created to integrate various climate system interactions, including the carbon cycle, climate feedback loops, and radiative forcing to simulate the effects of changing GHG emissions on atmospheric composition, radiative forcing, and global mean temperature change (Meinshausen, Raper, & Wigley, 2011). MAGICC is particularly advantageous because it emulates the complex and computationally intensive climate models efficiently (Department of Environmental Quality, 2025).

MAGICC uses representative concentration pathways (RCPs) to emulate future scenarios with varying degrees of GHG emission mitigation that result in predicted future changes in radiative forcing in terms of watts per square meter (W/m2). For example, RCP2.6 is representative of a sustainable GHG mitigation scenario that results in a radiative forcing increase of 2.6 W/m2 between the years 1750 and 2100. In contrast, RCP8.5 is representative of a high GHG emission scenario that results in a radiative forcing increase of 8.5 W/m2 between the years 1750 and 2100. For this analysis, DEQ chose to evaluate secondary impacts using both the RCP2.6 and RCP8.5 pathways because these scenarios span a range from high to low GHG emission mitigation, respectively. Importantly, testing two scenarios with significantly different GHG mitigation ensures that the nonlinear nature of induced climate impacts is conservatively estimated. In other words, the variable atmospheric concentration of GHGs over time affects the magnitude of impacts from a new source of emissions, as does the timing of the release of new GHG emissions from the proposed source. For example, the impacts of a GHG emission source are often greater in a sustainable (high mitigation) scenario such as RCP2.6 because the scenario assumes that global GHG emission rates decrease over time to a greater degree than most higher emission scenarios. The proposed source of emissions is therefore more impactful because it may represent an increasingly greater share of global emissions.

To contextualize the magnitude of future temperature impacts resulting from the Proposed Action's emissions, the MAGICC model was run for each RCP using both unmodified (base) emission scenarios and modified emission scenarios with the sum of Montana's GHG emissions subtracted. By comparing the results of the base and modified scenarios, it's possible to estimate the predicted future change in temperature that is attributable to a given quantity of emissions, as displayed in Table 2.

For the statewide emissions scenario in Table 2, the CO_2e emissions were subtracted from the RCP2.6 and RCP8.5 base scenario emission input files, and it was assumed that these annual GHG emissions correspond to a 20-year release. The emission input files for the online version of MAGICC contain global GHG emissions by GHG species for every decade rather than every year between 2020 and 2100, so the CO_2e emissions in Table 2 were subtracted from the 2030, 2040, and 2050 anchor points.

After the example GHG emissions were subtracted from the base scenarios, the model was run using probabilistic mode with the now-modified RCP2.6 and RCP8.5 emission input files. Running the model in probabilistic mode iterates the model run more than 100 times with slightly different internal parameters, resulting in a distribution of results. The default model output provides the predicted surface temperature increase above the 1850 to 1900 baseline period for every year between 1995 and 2100, and this annual temperature value is equal to the median value of the results distribution for that year. The base RCP2.6 and RCP8.5 scenarios (i.e., no emissions subtracted) were also run using probabilistic mode.

For each RCP scenario, the surface temperature results by year in the modified emission scenario were subsequently subtracted from the base emission scenario results, resulting in the increase above baseline future temperature change (ΔT) in degrees Celsius (°C) that can be attributed to Montana's statewide emissions. The final results for mid-century (2050) and end-of-century (2100) impacts are displayed in **Table 2**

Table 2. MAGICC Model across Different Annual Emissions.

Scenario	Annual Emissions (metric tons CO_2e/yr)	RCP2.6 ΔT by 2050 (°C)	RCP8.5 ΔT by 2050 (°C)	RCP2.6 ΔT by 2100 (°C)	RCP8.5 ΔT by 2100 (°C)
Statewide Emissions Scenario	50.74 million	0.0023	0.00049	0.00067	0.00057

Cumulative Impacts

Proposed Action: DEQ has determined that the use of the default data provides a reasonable representation of the GHG inventory for all of the state sectors, and an estimated annual GHG inventory by year.

The proposed action may contribute 556,988 metric tons from annual operation of CO_2e. The estimated emission of 556,988 metric tons of CO_2e for this proposed action would contribute ((556,988/1,000,000))/51.04 or 1.1 percent of Montana's annual CO_2e emissions. The 51.04 million metric tons is for the year 2022, and the Table 2 value of 50.74 represents a three-year average for 2020, 2021 and 2022. To address any concerns regarding the ability of the MAGICC model to correctly predict the impacts of very small CO_2e contributions from projects, DEQ has instead opted to compare the project to the temperature range increase associated with the entire State of Montana inventory. Therefore, Montana's contribution ranges from 0.0023 °C by 2050 to 0.00067°C by 2100. The project emissions are approximately 1.1 percent of the state inventory, and would have a much smaller impact than the entire state's inventory does on increasing worldwide ambient temperature.

Description of Alternatives

No Action Alternative: In addition to the proposed action, DEQ must also considered a "no action" alternative. The "no action" alternative would deny the approval of the proposed action. The applicant would lack the authority to conduct the proposed activity. Any potential impacts that would result from the proposed action would not occur. The no action alternative forms the baseline from which the impacts of the proposed action can be measured.

If the applicant demonstrates compliance with all applicable rules and regulations required for approval, the "no action" alternative would not be appropriate.

Other Reasonable Alternative(s): Describe any other alternatives that were considered.

In order to meet the project objective of producing renewable diesel and sustainable aviation fuels, specific raw materials and energy inputs are necessary, and while the configuration for these processes could be modified for a different physical layout, a significant energy input is necessary to treat and convert the agricultural and animal-based materials and therefore the associated emissions would not be substantially different than the proposed action.

Consultation

DEQ engaged in internal and external efforts to identify substantive issues and/or concerns related to the proposed project. Internal scoping consisted of internal review of the environmental assessment document by DEQ staff.

A review of the Cascade County website, and listed department information identified several programs such as Cascade County Zoning Regulations (Revised December 2021), Cascade County Floodplain Regulations (Revised March 2013), Cascade County Subdivisions (Revised 2018) and a Growth Policy Update May 2014. There may be elements of these programs that would apply to land development, industry standards and manufacturing that might be covered by these over-arching policies.

Public Involvement

The public comment period for this permit action will occur from November 14, 2025, through December 1, 2025.

Significance of Potential Impacts and Need for Further Analysis

When determining whether the preparation of an environmental impact statement is needed, DEQ is required to consider the seven significance criteria set forth in ARM 17.4.608, which are as follows:

- The severity, duration, geographic extent, and frequency of the occurrence of the impact;
- The probability that the impact will occur if the proposed action occurs; or conversely, reasonable assurance in keeping with the potential severity of an impact that the impact will not occur;
- Growth-inducing or growth-inhibiting aspects of the impact, including the relationship or contribution of the impact to cumulative impacts – identify the parameters of the proposed action;
- The quantity and quality of each environmental resource or value that would be affected, including the uniqueness and fragility of those resources and values;
- The importance to the state and to society of each environmental resource or value that would be affected;
- Any precedent that would be set as a result of an impact of the proposed action that would commit the department to future actions with significant impacts or a decision in principle about such future actions; and
- Potential conflict with local, state, or federal laws, requirements, or formal plans.

Conclusions and Findings

DEQ finds that this action results in minor impacts to air quality and GHG emissions in Cascade County, Montana.

No significant adverse impacts would be expected because of the proposed project. As noted through the draft EA, the severity, duration, geographic extent and frequency of the occurrence of the impacts associated with the proposed air quality project would be limited. The proposed action increases the throughput of renewable fuel products from 16,140 barrels per day (bpd) capacity to 24,000 bpd. Physical changes to the facility include new process equipment and modified equipment to accommodate the increase in production

The site is permitted to operate the primary new main equipment up to 8,760 hours per calendar year using BACT as implemented into the enforceable permit conditions. Some process equipment also utilizes expected periods of startup, shutdown and malfunction where equipment is not in normal operation.

As discussed in this EA, DEQ has not identified any significant impacts associated with the proposed actions for any environmental resource. DEQ does not believe that the activities proposed by the Applicant would have any growth-inducing or growth-inhibiting aspects, or contribution to cumulative impacts.

There are no unique or known endangered fragile resources in the project area and no underground disturbance would be required for this project.

There would be negligible to minor impacts to view-shed aesthetics as the additional equipment adds to industrial infrastructure operating on the site. Some new stack heights may be equal or taller than similar equipment on site.

Demands on the environmental resources of land, water, air, or energy would be negligible to minor.

Impacts to human health and safety would not be significant as access to the site would be restricted to authorized personnel only, and because the site is on private land.

As discussed in this EA, DEQ has not identified any significant impacts associated with the proposed activities on any environmental resource.

Issuance of a Montana Air Quality Permit #5263-03 to the Applicant does not set any precedent that commits DEQ to future actions with significant impacts or a decision in principle about such future actions. If the Applicant submits another modification or proposes to amend the permit, DEQ is not committed to issuing those revisions.

DEQ would conduct an environmental review for any subsequent permit modifications sought by the Applicant pursuant to MEPA. DEQ would make permitting decisions based on the criteria set forth in the Clean Air Act of Montana.

Issuance of the Permit to the Applicant does not set a precedent for DEQ's review of other applications for Permits, including the level of environmental review. The level of environmental review decision is made based on case-specific consideration of the criteria set forth in ARM 17.4.608.

Finally, DEQ does not believe that the proposed air quality permitting action by the Applicant would have any growth-inducing or growth inhibiting impacts that would conflict with any local, state, or federal laws, requirements, or formal plans.

Based on a consideration of the criteria set forth in ARM 17.4.608, no significant adverse impacts to the affected human environment would be expected because of the proposed project. Therefore, preparation of an Environmental Impact Statement or EIS is not required, and the draft EA is deemed the appropriate level of environmental review pursuant to MEPA.

PREPARATION

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November 14, 2025

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Date

REFERENCES

- 2021 BLM Specialist Report on Annual Greenhouse Gas Emissions and Climate Trends, https://www.blm.gov/

- https://www.blm.gov/content/ghg/?year=2022

- BLM 2023
  2023 BLM Specialist Report:
  2023 BLM Specialist Report on Annual Greenhouse Gas Emissions and Climate Trends

Air Quality Permit Application Received July 15, 2025
Incompleteness Letter Sent on August 4, 2025
Incompleteness Letter Received September 3, 2025
Additional Information Received on September 15, 2025
MRL Request for Application Extension received October 2, 2025
DEQ Approval of Application Extension October 3, 2025
DEQ Receipt of Modeling Demonstration October 17, 2025
Application Completeness Letter sent based on October 17, 2025, MRL submittal
Montana State Historical Preservation Office (SHPO) Report From August 25, 2021
Montana Natural Heritage Program (Website Search Downloads) From Download Aug 15, 2021
Montana Natural Heritage Program Download October 9, 2025
Montana DEQ Cadastral GIS Layer – Through-Out Project Up Until Draft Issuance
NRCS Soil Survey Website Accessed October 6, 2025
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 #2161-35
City of Great Falls Website – Planning Documents
Cascade County Website
Wind Rose Information – Great Falls International Airport
Montana DEQ Draft GHG Guidance Document (SB211)