November 14, 2017

Mr. Wayne Leiker
Calumet Montana Refining, LLC
1900 10th Street NE
Great Falls, MT 59404

Dear Mr. Leiker:

Montana Air Quality Permit #2161-30 is deemed final as of November 14, 2017, by the Department of Environmental Quality (Department). This permit is for Calumet Montana Refining, LLC's Great Falls Petroleum Refinery. All conditions of the Department's Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

For the Department,

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

Shawn Juers
Environmental Engineer
Air Quality Bureau
(406) 444-2049

JM:SJ
Enclosure

Montana Department of Environmental Quality
Air, Energy & Mining Division

Montana Air Quality Permit #2161-30

Calumet Montana Refining, LLC
1900 10th Street NE
Great Falls, MT 59404
NE ¼ of Section 1, Township 20 North, Range 3 East, in Cascade County

November 14, 2017

MONTANA AIR QUALITY PERMIT

Issued to:	Calumet Montana Refining, LLC 1900 10th Street North East Great Falls, MT 59404	MAQP: #2161-30 Application Received: 4/4/2017 Application Deemed Complete: 9/8/2017 Preliminary Determination Issued: 9/26/2017 Department Decision Issued: 10/27/2017 Permit Final: 11/14/2017 AFS#: 013-0004

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

SECTION I: Permitted Facilities

A. Plant Location

Calumet operates a petroleum refinery located at the NE ¼ of Section 1, Township 20 North, Range 3 East, in Cascade County, Montana. The refinery is located along the Missouri River in Great Falls, Montana.

B. Permitted Facility

The major permitted equipment at Calumet includes:

- #1 Crude Unit (up to 10,000 barrels per stream day (bpsd));
- #2 Crude Unit (up to 20,000 bpsd));
- Fluid Catalytic Cracking Unit (FCCU);
- Mild Hydrocracker Unit (MHC);
- Hydrogen Plant #1, #2, and #3;
- Catalytic Reformer Unit;
- Naphtha Hydrodesulfurization (HDS);
- Diesel HDS;
- Catalytic Poly Unit;
- Hydrogen Fluoride (HF) Alkylation Unit;
- Deisobutanizer Unit;
- Sodium Hydrosulfate (NaHS) Unit;
- Hydrotreater Unit (HTU);
- Process Heaters for #2 Crude Unit (Crude Heater, Vacuum Heater, Combined Feed Heater, Fractionation Feed Heater);
- Polymer-Modified Asphalt (PMA) Unit;
- Storage Tanks (heated asphalt, crude oil, and petroleum products);
- Gasoline Truck Loading with a vapor combustor unit (VCU);
- Gasoline Railcar Loading with a VCU;
- Asphalt/Diesel Loading and Crude Oil/Gas Oil Rail Unloading Rack;

- Primary Flare #1 and Secondary Flare #2;
- Miscellaneous Tanks; and
- Utilities (Boilers (#1, #2 and #3), Boiler #4 (Temporary Boiler), cooling towers, wastewater treatment including new Dissolved Air Flotation Unit);
- Sour Water Stripper Ammonia Combustor

A complete list of permitted equipment for Calumet is contained in Section I.A. of the permit analysis.

C. Current Permit Action

On April 4, 2017 the Montana Department of Environmental Quality – Air Quality Bureau received an application from Calumet to modify the existing MAQP. Incompleteness responses and additional information were received, with final information completing the application on September 26, 2017. Due to various operational and design issues, compliance with certain limits associated with the expansion project permitted in MAQP #2161-29 were determined to be unachievable on a continuous and ongoing basis. These limitations were necessary to avoid the project being determined a major modification of a major stationary source and subject to the permitting requirements of ARM 17.8 Subchapter 8 for oxides of nitrogen (NO_x). As such, Calumet has proposed an alternative operating scenario and alternative limitations to maintain the project below relevant significant emissions rates.

Calumet proposes to install a new temporary low NO_x boiler (Boiler #4) for additional/supplemental steam production and an ammonia combustor to remove and combust fuel bound nitrogen that otherwise would be present in refinery fuel gas. In addition, Calumet has proposed an umbrella limit on emissions of NO_x and carbon monoxide (CO) on a rolling 12-month basis. The umbrella limit would apply to combined emissions from multiple units such that any combination of emissions from these units, provided the overall emissions limitation is adhered to, maintains the project as not a major modification for NO_x or CO. Prior limitations related to PSD avoidance on Boilers #1 and #2 have been removed from the permit.

Calumet has determined a need to reduce fuel-bound nitrogen in fuel gas in order to meet NO_x limitations on various units. Further, Calumet has identified mechanical issues with Boiler #3 which has resulted in the potential for excess NO_X emissions. Bringing a temporary low NO_X boiler on-site will allow Calumet to produce steam for operations while ongoing efforts are undertaken to reduce plant wide NO_X emissions. The low NO_X boiler will provide for reduced emissions of NO_X per pound of steam produced compared to the NO_X performance capabilities of Boilers #1 and #2.

Boiler #3, the new low NO_x boiler, and the ammonia combustor were determined technically and economically related to the expansion project and were included in the expansion project as new units. The purpose of this permitting action is to establish limits which maintain the net emissions increases to less than the significant emissions rates for NO_x and CO, or less than the amount of other emissions previously reviewed for the expansion project. All pollutants were reviewed and the project was re-permitted as if the project had not been previously permitted. A request in the future to modify or replace associated units would require a reassessment of the project emissions. The allowable operating capacity of the associated refining unit heaters as a whole was reduced in the current operational scenario, and future projects to reduce emissions will be necessary to gain full use of the increased refining capacity capable of being accomplished with the associated equipment installed for avoidance of PSD.

During PSD review, Calumet identified that Tank #50 and #102 will not be equipped with tank heaters and the emissions were removed from considerations in contemporaneous emissions increases.

SECTION II: Limitations and Conditions

A. General Facility Conditions

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

   i. Subpart A – General Provisions shall apply to all equipment or facilities subject to an NSPS Subpart as listed below.

   ii. Subpart Dc – Standards of Performance for Small Industrial–Commercial Institutional Steam Generating Units for which construction, modification, or reconstruction is commenced after June 9, 1989. This Subpart applies to Boiler #3.

   iii. Subpart J – Standards of Performance for Petroleum Refineries applies to all fuel gas combustion devices with the exception of those subject to 40 CFR 60, Subpart Ja.

   iv. FCCU regenerator: for carbon monoxide (CO) and sulfur dioxide (SO_2) (pursuant to Calumet's Consent Decree (Consent Decree)).

   v. Heaters and boilers (Consent Decree).

   vi. Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification commenced after May 14, 2007 (H-2101, H-2102, H-4101, H-4102, H-31A, H-31B, Boiler #3, flare system, fuel gas treatment unit (FGT), and sour water stripper (SWS)).

   vii. Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984.

   viii. Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture shall apply to all asphalt storage tanks that processes and stores only non-roofing asphalts, and was constructed or modified since May 26, 1981.

ix. Subpart VV – Standards of Performance for Equipment Leaks of Volatile Organic Compounds (VOC) in the Synthetic Organic Chemicals Manufacturing Industry, shall apply to this refinery as required by 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC.

x. Subpart VVa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.

xi. Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries shall apply to the NaHS Unit, Diesel/Gas Oil HDS Unit, Hydrogen Plant, and any other equipment as appropriate. A monitoring and maintenance program as described under 40 CFR 60, Subpart VV shall be instituted.

xii. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006. Unless Calumet demonstrates exemption from this standard, the standard applies to compressors, valves, pumps, pressure relief devices, sampling connection system, open-ended valves and lines, flanges, and connectors that are part of the Low Sulfur Fuels expansion project.

xiii. Subpart QQQ – Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply to the wastewater treatment system, individual drains, oil-water separators, HTU, Hydrogen Unit, and any other applicable equipment constructed, modified or reconstructed after May 4, 1987.

2. Calumet shall comply with all applicable requirements of ARM 17.8.341, as specified by 40 CFR Part 61, National Emissions Standards for Hazardous Air Pollutants:

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

   b. Subpart FF – National Emission Standard for Benzene Waste Operations.

3. Calumet shall comply with all applicable requirements of ARM 17.8.342, as specified by 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants (NESHAP) for Source Categories:

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

b. Subpart R – NESHAP for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), as specified under Subpart CC.

c. Subpart CC – NESHAP from Petroleum Refineries shall apply to, but not be limited to, the bulk loading racks (including the gasoline truck loading and railcar loading racks), certain valves and pumps in the alkylation unit, miscellaneous process vents, storage vessels, wastewater, and equipment leaks. The gasoline loading rack provisions in Subpart CC require compliance with applicable Subpart R provisions, and the equipment leak provision requires compliance with applicable 40 CFR 60, Subpart VV provisions.

d. Subpart UUU – NESHAP from Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, shall apply to, but not be limited to, the FCCU and the Catalytic Reformer Unit.

e. Subpart EEEE – NESHAP for Organic Liquids Distribution (Non-Gasoline) shall apply to, but not be limited to, Tank # 1 – diethylene glycol monoether (DEGME) and the naphtha loading rack.

f. Subpart DDDDD – NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters shall apply to, but not be limited to, all boilers and process heaters, with exception of Boiler #4 if it is determined to meet the definition of a temporary boiler as defined in this subpart.

B. Emission Control Requirements:

Calumet shall install, operate and maintain the following equipment and practices as specified:

1. Flare #1 (primary flare) shall be equipped with a flare gas scrubber (ARM 17.8.749 and ARM 17.8.752).

2. Flare #2 (secondary flare) must maintain a water seal except during periods of startup, shutdown, or malfunction. These periods of startup, shutdown, and malfunction shall not exceed 9 hours per year based on a 12-month rolling average (ARM 17.8.749).

3. Hydrogen plant reformer heaters shall only be fired with commercially available natural gas, which may include recycled gas from the hydrogen plants, and shall not be fired with refinery fuel gas or refinery Liquefied Petroleum Gas (LPG). The diesel/gas oil HDS heater shall be fired with only purchased natural gas or refinery fuel gas that meets 40 CFR 60, Subpart J or Ja requirements. The purge (vent) gas used as fuel in the hydrogen plant reformer heaters shall be sulfur-free (ARM 17.8.752).

4. Hydrogen Plant #2 must be equipped with a next-generation ultra-low NO_x burner (ULNB) on the heater (Consent Decree and ARM 17.8.749).

5. Hydrogen Plant #3 must be equipped with ULNB and the total combined capacity of the two heaters (H-31A and H-31B) shall not exceed 134 MMBtu/hr (ARM 17.8.752).

6. All process heaters in the #2 Crude Unit (H-2101, H-2102, H-4101, H-4102) shall be equipped with ULNB (ARM 17.8.749 and ARM 17.8.752).

7. Storage Tanks

   a. Storage tanks #47, #48, #49, #54, and #58 shall be used to store kerosene/Jet A and shall be equipped with fixed roof tanks (ARM 17.8.749 and ARM 17.8.752).

   b. Storage tanks #50 and #102 shall be equipped with a fixed roof (ARM 17.8.752).

   c. Storage tanks #100 and #101 shall be used to store #5 Fuel Oil and shall be equipped with a fixed roof (ARM 17.8.749).

   d. Storage tank #52 shall be used to store premium gasoline and shall be equipped with external floating roofs and a mechanical shoe seal (ultracheck safe sleeve or equivalent) (ARM 17.8.752).

   e. Storage tanks #123, #126 and #127 shall be used to store unleaded gasoline and shall be equipped with an external floating roof and a mechanical shoe seal (ultracheck safe sleeve guide pole) (ARM 17.8.749 and ARM 17.8.752).

   f. Storage tanks #57 and #124 shall be used to store Naptha, and Tank #57 shall be equipped with a double seal internal floating roof (ARM 17.8.752).

   g. Storage tanks #122, #124, #125, #126, #145B, #201, #202, and #203 shall be equipped with dual-seal external floating roofs with guide pole sleeves (ARM 17.8.752).

   h. Storage tank #128 shall be equipped with dual-seal external floating roofs. The primary seals shall be visually inspected for holes every 5 years and the secondary seals shall be visually inspected for holes annually (ARM 17.8.752).

   i. Storage tanks #50, #55, #56, #69 #102, #110, #112, #130, #132, #133, #135, #137, #139, and #140 shall be used for heavy oil (ARM 17.8.749).

   j. Storage tanks #201, #202, and #203 shall be used for crude oil service (ARM 17.8.749).

   k. Storage tanks #8 and #9 shall be used for caustic service (ARM 17.8.749).

l. Asphalt tank heaters #135, #137, #139 and #140 shall burn only natural gas or refinery fuel gas in compliance with 40 CFR 60, Subpart J (ARM 17.8.749, Consent Decree, and 40 CFR 60, Subpart J).

m. Asphalt tank heater #160 shall burn only natural gas or refinery fuel gas in compliance with 40 CFR 60, Subpart Ja (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60, Subpart Ja).

n. The three 0.75 MMBtu/hr PMA tank heaters (tanks #130, #132, and #133), shall burn natural gas or refinery fuel gas in compliance with 40 CFR 60, Subpart J (ARM 17.8.752, Consent Decree, and 40 CFR 60, Subpart J).

o. Calumet shall not cause to be discharged into the atmosphere from any asphalt tank constructed or modified since May 26, 1981, exhaust gases with opacity greater than 0% except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for clearing (ARM 17.8.340 and 40 CFR 60, Subpart UU).

p. For any asphalt tank constructed between November 23, 1968, and May 26, 1981, or any other tank constructed since November 23, 1968, Calumet shall not cause to be discharged into the atmosphere exhaust gases with an opacity of 20% or greater, averaged over 6 consecutive minutes (ARM 17.8.304).

q. For any tank constructed prior to November 23, 1968, Calumet shall not cause to be discharged into the atmosphere exhaust gases with an opacity of 40% or greater, averaged over 6 consecutive minutes (ARM 17.8.304).

8. Pressure Vessels – All pressure vessels in HF Acid service, except storage tanks, shall be vented to the flare system (ARM 17.8.749 and ARM 17.8.752).

9. The HF Alkylation Unit shall be operated and maintained as follows (ARM 17.8.749 and ARM 17.8.752):

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

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

c. All pumps used in the alkylation plant shall be fitted with the highest quality state-of-the-art mechanical seals.

d. All pumps shall be monitored and maintained as described in 40 CFR 60.482-2 and all control valves shall be monitored and maintained as described in 40 CFR 60.482-7. All other potential sources of VOC leaks shall be inspected quarterly for evidence of leakage by visual or other detection methods. Repairs shall be made promptly as described in 40 CFR 482-7(d). Records of monitoring and maintenance shall be maintained on site for a minimum of 2 years.

e. All process drains shall consist of water seal traps with covers.

f. All equipment shall be operated and maintained as described in 40 CFR 60.692-2, 60.692-6, and 60.693-1. Inspection reports shall be made available for inspection upon request.

g. The Alkylation Unit process heater shall burn only natural gas or fuel gas in compliance with 40 CFR 60, Subpart J (ARM 17.8.749, Consent Decree, and 40 CFR 60, Subpart J).

10. The PMA Unit shall be operated and maintained as follows:

a. All open-ended valves shall have plugs or caps installed on the open end (ARM 17.8.752).

b. All pumps in the PMA unit shall be equipped with standard single seals (ARM 17.8.752).

c. All pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors shall meet the standards described in 40 CFR 60.482-8. Repairs shall be made promptly as described in 40 CFR 60.482-7(e) (ARM 17.8.752).

11. Calumet shall ensure that the NaHS Unit, Diesel/Gas Oil HDS Unit, Hydrogen Plants, and any other equipment as appropriate, comply with the applicable requirements in 40 CFR 63, Subpart GGG, including (ARM 17.8.342 and 40 CFR 63, Subpart GGG):

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

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

c. A monitoring and maintenance program as described under 40 CFR 60, Subpart VV shall be instituted.

12. Calumet shall ensure that all process drains consist of water seal traps with covers, for the HTU, Hydrogen Units, and any other equipment as appropriate (ARM 17.8.342 and 40 CFR 63, Subpart QQQ).

13. Cooling Towers – Cooling water shall be monitored twice per shift for changes, specifically pH and hydrocarbon content. The appearance of the towers and related equipment shall be inspected at least once per shift (ARM 17.8.749 and ARM 17.8.752).

14. Calumet must install, operate, and maintain an ULNB and flue gas recirculation (FGR) on Boiler #3 (ARM 17.8.752).

15. Boiler #3 shall only combust pipeline quality natural gas, refinery fuel gas or SWSOH (ARM 17.8.752).

16. When the SO_2/O_2 Continuous Emissions Monitoring System (CEMS) is operational on the boiler stacks, Calumet may incinerate the HTU SWSOH in the #1, #2 and #3 boilers. Incineration of the SWSOH and combustion of any refinery fuel gas shall meet the applicable limitations in 40 CFR 60, Subpart J (Boiler #1 and Boiler #2) or Subpart Ja (Boiler #3), as applicable (Consent Decree, ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart J and 40 CFR 60, Subpart Ja).

17. Calumet shall not re-activate the old SWS unit that was taken out of stripping service in 2006, without conducting a permitting analysis in conformance with ARM 17.8 Subchapter 7, and obtaining Department approval, in writing (ARM 17.8.749).

18. The gasoline and distillates truck loading rack shall be operated and maintained as follows:

    a. Calumet's tank truck loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from cargo tanks during gasoline product loading (ARM 17.8.342).

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

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

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

    e. The vapor collection system shall be designed to prevent any VOC vapors collected at one loading position from passing to another loading position (ARM 17.8.342).

    f. Loadings of liquid products into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks, using the following procedures (ARM 17.8.342):

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

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

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

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

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

A. The gasoline cargo tank meets the applicable test requirements in 40 CFR 63.425(e) to this permit;

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

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

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

g. Calumet shall ensure that loadings of gasoline cargo tanks at the truck loading rack are made only into cargo tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system (ARM 17.8.342).

h. Calumet shall ensure that the terminal and the cargo tank vapor recovery systems are connected during each loading of a gasoline cargo tank at the truck loading rack (ARM 17.8.342).

i. Calumet shall monitor and maintain all pumps, shutoff valves, relief valves, and other piping and valves associated with the gasoline loading rack as described in 40 CFR 60.482-1 through 60.482-10.

j. The truck loading rack VCU stack shall be at least 35 feet above grade (ARM 17.8.749).

19. The gasoline railcar loading rack and VCU shall be operated and maintained as follows:

a. Gasoline and naphtha will be the only products loaded from the gasoline railcar loading rack (ARM 17.8.749).

b. Calumet's gasoline railcar loading rack shall be equipped with a vapor recovery system designed to collect the organic compounds displaced from railcar product loading and vent those emissions to the VCU (ARM 17.8.342 and 40 CFR 63, Subpart CC and ARM 17.8.752).

c. Calumet shall operate and maintain the VCU to control VOC and hazardous air pollutant (HAP) emissions during the loading of gasoline or naphtha in the gasoline railcar loading rack. Calumet's collected vapors shall be routed to the VCU at all times (ARM 17.8.752).

d. The vapor recovery system shall be designed to prevent any VOC vapors collected at one loading position from passing to another loading position (ARM 17.8.749).

e. Loading of gasoline and naphtha railcars shall be restricted to the use of submerged fill and dedicated normal service (ARM 17.8.752).

f. Calumet shall ensure that loading of railcars at the gasoline railcar loading rack are made only into railcars equipped with vapor recovery equipment that is compatible with the terminal's vapor recovery system (ARM 17.8.749).

g. Loadings of gasoline into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks, using procedures as listed in 40 CFR 63, Subpart R (ARM 17.8.342 and 40 CFR 63, Subpart CC, and ARM 17.8.752).

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

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

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

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

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

        A. The gasoline cargo tank meets the applicable test requirements in 40 CFR 63.425(e) to this permit;

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

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

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

h. Calumet shall ensure that the terminal's and the railcar's vapor recovery systems are connected during each loading of a railcar at the gasoline railcar loading rack (ARM 17.8.749).

i. The vapor recovery and liquid loading equipment shall be designed and operated to prevent gauge pressure in the gasoline railcar from exceeding 4,500 Pa (450 mm of water) during gasoline loading. This level shall not be exceeded when measured by the procedures specified in 40 CFR 60.503(d) (ARM 17.8.342 and 40 CFR 63, Subpart CC).

j. No pressure-vacuum vent in the permitted terminal's vapor recovery system shall begin to open at a system pressure less than 4,500 Pa (450 mm of water) (ARM 17.8.749).

k. Calumet shall comply with the applicable provisions of 40 CFR 60, Subpart VV, including Calumet shall monitor and maintain all pumps, shutoff valves, relief valves, and other piping and valves associated with the gasoline loading rack as described in 40 CFR 60.482-1 through 60.482-10 (ARM 17.8.749, ARM 17.8.342 and 40 CFR 63, Subpart CC).

l. The gasoline railcar loading rack VCU stack exhaust exit shall be at least 30 feet above grade (ARM 17.8.749).

20. Calumet shall not combust any fuel gas with a hydrogen sulfide (H_2S) concentration in excess of 230 milligram per dry standard cubic meter (mg/dscm) equivalent to 0.10 grains per dry standard cubic foot (gr/dscf) in any applicable fuel gas combustion device (Consent Decree, ARM 17.8.340 and 40 CFR 60, Subpart J).

21. For fuel gas combustion devices where construction, reconstruction, or modification commenced after May 14, 2007, Calumet shall not burn any fuel gas that contains H_2S in excess of 162 parts per million volume, dry basis (ppm_{vd}) determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppm_{vd} determined daily on a 365-successive calendar day rolling average basis (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Ja).

22. Calumet shall not combust fuel oil in any combustion unit, except torch oil may be used in the FCCU Regenerator during FCCU startups (Consent Decree).

23. The #1 crude unit's stack height shall be at least 150 feet above ground level (ARM 17.8.749).

C. Emission Limitations:

1. Plant-wide refinery emissions shall not exceed (ARM 17.8.749):

a. SO_2:

Annual	1,515 tons per year (TPY)
Daily	4.15 tons/rolling 24-hours

b. CO:

Annual	4,700 TPY
Daily	12.9 tons/rolling 24-hours

2. Boiler #4 (Temporary Boiler)

3. The maximum rated capacity of the Temporary Boiler, corrected for elevation, shall not exceed 91.7 MMBtu/hr on a higher heating value basis (ARM 17.8.749).

4. The Temporary Boiler shall be fired on pipeline quality natural gas only (ARM 17.8.749 and ARM 17.8.752).

5. NO_X emissions from the Temporary Boiler shall not exceed 0.039 lb/MMBtu averaged over three one-hour test runs (ARM 17.8.752).

6. CO emissions from the Temporary Boiler shall not exceed 0.040 lb/MMBtu averaged over three one-hour test runs (ARM 17.8.752).

7. Boiler #1 and #2 emissions shall not exceed:

a. SO_2 (ARM 17.8.749):

i. Annual: 648 TPY averaged over a 1-year period
ii. Hourly: 148 pounds per hour (lb/hr) averaged over 1 year
iii. 174 lb/hr averaged over a 24-hour period
iv. 355 lb/hr averaged over a 3-hour period

b. Oxides of Nitrogen (NO_x): 76.50 lb/hr (ARM 17.8.752):

c. CO (ARM 17.8.752):

i. Annual 4.4 TPY
ii. Hourly 1.00 lb/hr

d. Opacity from Boilers #1 and #2 shall not exceed 40% averaged over any 6 consecutive minutes (ARM 17.8.304).

8. Boiler #3 emissions:

   a. The maximum rated capacity of Boiler #3 shall not exceed 60.5 MMBtu/hr on a higher heating value basis (ARM 17.8.749).

   b. Opacity from the Boiler #3 shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

   c. NO_x emission limit shall be based on the actual performance as demonstrated by the required initial performance test, but shall not exceed 0.019 pounds per million British thermal units (lb/MMBtu) (1.15 lb/hr) on a 3-hour average basis (Consent Decree, ARM 17.8.752, ARM 17.8.749).

   d. SO_2 emissions shall not exceed 20 parts per million volume, dry (ppm_{vd}) at 0% oxygen (ARM 17.8.752).

   e. CO emissions shall not exceed 0.034 lb/MMBtu based on a 3-hour average (ARM 17.8.752).

9. HDS Furnace Stack

   a. NOx emissions shall not exceed the limit of 0.07 lb/MMBtu, 1.42 lb/hr, or 6.2 TPY (ARM 17.8.752).

   b. CO emissions shall not exceed the limit of 0.79 lb/hr or 3.5 TPY (ARM 17.8.752).

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

10. Hydrogen Plant Reformer Furnace Stack

   a. NOx emissions shall not exceed the limit of 0.07 lb/MMBtu, 1.90 lb/hr, or 8.3 TPY (ARM 17.8.752).

   b. CO emissions shall not exceed the limit of 0.93 lb/hr or 4.1 TPY (ARM 17.8.752).

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

11. Hydrogen Plant #2

   a. NO_X emissions from the process heater shall be controlled by a next generation ULNB and shall not exceed 0.033 lb/MMBtu based on the higher heating value (HHV) (ARM 17.8.752 and Consent Decree).

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

12. Hydrogen Plant #3 (Reformers H-31A and H-31B)

a. The maximum rated capacity of the Hydrogen Plant Reformer A and Hydrogen Plant Reformer B heaters shall not exceed 67.0 MMBtu/hr on a higher heating value basis each. (ARM 17.8.749)

b. NO_x emissions from each heater shall be controlled by an ULNB and shall not exceed 0.051 lb/MMBtu based a 30-day rolling average (ARM 17.8.752).

c. For process heaters (forced draft) with a rated capacity of greater than 40 MMBtu/hr-HHV, Calumet shall comply with 40 CFR 60, Subpart Ja. Each applicable process heater must meet the NO_X emission limits in either (b)(i) or (b)(ii), as follows (ARM 17.8.340 and 40 CFR 60, Subpart Ja):

i. 60 ppm_{vd} (corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

ii. 0.060 lb/MMBtu-HHV basis determined daily on a 30-day rolling average basis.

d. Calumet shall control particulate matter (PM), PM with an aerodynamic diameter of 10 microns or less (PM_{10}), and PM with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$) emissions from each heater by utilizing good combustion practices and only combusting low sulfur fuels (ARM 17.8.752):

i. PM/PM_{10} emissions shall not exceed 0.00051 lb/MMBtu based on a 30-day rolling average, and

ii. $PM_{2.5}$ emission shall not exceed 0.00042 lb/MMBtu based on a 30-day rolling average

e. Calumet shall control CO emissions using good combustion practices and CO emissions shall not exceed 0.03 lb/MMBtu based on a 30-day rolling average, or 17.6 tons per year based on a 12-month rolling average (ARM 17.8.752).

f. The combined carbon dioxide equivalent (CO_2e) emissions from the reformer heaters shall not exceed 133,038 TPY based on a 12-month rolling average (ARM 17.8.752).

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

13. #2 Crude Unit process heaters (Atmospheric Unit Heater H-2101, Vacuum Unit Heater H-2102, MHC Combined Feed Heater H-4101, MHC Fractionation Heater H-4102)

a. The maximum rated capacity of each unit shall not exceed the following on a higher heating value basis (ARM 17.8.749):

   i. #2 Crude Atmospheric Heater H-2101: 71.0 MMBtu/hr

   ii. #2 Crude Vacuum Heater H-2102: 27.0 MMBtu/hr

   iii. MHC Combined Feed Heater H-4101: 54.0 MMBtu/hr

   iv. MHC Reactor Fractionation Heater H-4102: 38.0 MMBtu/hr

b. Each fuel combustion device must be equipped with an ULNB and NOx emissions shall not exceed 0.035 lb/MMBtu-HHV based on a 30-day rolling average (ARM 17.8.749, ARM 17.8.752).

c. For process heaters (natural draft) with a rated capacity of greater than 40 MMBtu/hr-HHV, Calumet shall comply with 40 CFR 60, Subpart Ja. Each applicable process heater must meet the NOx emission limits in either (b)(i) or (b)(ii), as follows (ARM 17.8.340 and 40 CFR 60, Subpart Ja):

   i. 40 ppmvd (corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

   ii. 0.040 lb/MMBtu-HHV basis determined daily on a 30-day rolling average basis.

d. Each applicable fuel gas combustion device shall comply with 40 CFR 60, Subpart Ja by meeting the applicable SO_2 or H_2S emission limit in 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja):

   i. Calumet shall not discharge or cause the discharge of any gases into the atmosphere that contain SO_2 in excess of 20 ppmv (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling basis; and SO_2 in excess of 8 ppmv (dry basis corrected to to 0-percent excess air) determined daily on a 365 successive calendar day rolling average basis; or

   ii. Calumet shall not burn in any fuel gas combustion device any fuel that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis, and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

e. Calumet shall control PM/PM_{10} and $PM_{2.5}$ emissions from each heater by utilizing good combustion practices and only combusting low sulfur fuels (ARM 17.8.752):

   i. PM/PM_{10} emissions from each heater shall not exceed 0.00051 lb/MMBtu based on a 30-day rolling average, and

ii. $PM_{2.5}$ emission from each heater shall not exceed 0.00042 lb/MMBtu based on a 30-day rolling average.

f. Calumet shall control CO emissions from each process heater using good combustion practices. CO emissions from each heater shall not exceed 0.055 lb/MMBtu, based on a 30-day rolling average (ARM 17.8.752).

g. Calumet shall control CO_2e emission from each process heater by using low carbon fuels, good combustion practices and an energy efficient design. The CO_2e emissions shall not exceed (ARM 17.8.752):

i. 142 lb/MMBtu based on a 30-day rolling average for the Crude Heater (H-2101) and Vacuum Heater (H-2102).

ii. 141 lb/MMBtu based on a 30-day rolling average for the Combined Feed Heater (H-4101) and Fractionator Feed Heater (H-4102).

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

14. Flare System (Flare #1 and Flare #2)

a. Calumet shall comply with the requirements of 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

15. Gasoline Truck Loading Rack

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

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

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

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

i. Any visible emissions that exhibit an opacity of 10% or greater (ARM 17.8.752); and

ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% carbon dioxide (CO_2) (ARM 17.8.752).

16. Gasoline Railcar Loading Rack

a. The total VOC emissions to the atmosphere from the VCU due to loading gasoline into railcars shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.342 and 40 CFR Part 63.422, and ARM 17.8.752).

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

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

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

   i. Any visible emissions that exhibit an opacity of 10% or greater (ARM 17.8.752); and

   ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO_2 (ARM 17.8.752).

17. FCCU

Calumet shall not cause or authorize to be discharged into the atmosphere from the FCCU emissions in excess of:

a. 15.0 lb/hr of PM (Consent Decree)

b. Opacity shall not exceed 40%, except for one 6 minute average in any 1 hour (ARM 17.8.304).

c. CO

   i. 500 ppmvd, at stack oxygen (or, “uncorrected”) (40 CFR 63, Subpart UUU and 40 CFR 60, Subpart J)

   ii. 500 ppmvd, corrected to 0% oxygen (O_2) 1-hour average (Consent Decree)

   iii. 100 ppmvd, corrected to 0% O_2 on a 365-day rolling average (Consent Decree)

d. SO_2

   i. 50 ppmvd, corrected to 0% O_2, on a 7-day rolling average, except for periods of hydrotreater outages (Consent Decree)

   ii. 25 ppmvd, corrected to 0% O_2, on a 365-day rolling average (Consent Decree)

e. NO_x

i. 87 ppmvd, corrected to 0% O_2, on a 7-day rolling average, except for periods of startup, shutdown, malfunction or hydrotreater outages

ii. 68 ppmvd, corrected to 0% O_2, on a 365-day rolling average

18. MAQP #2161-30 NO_X Umbrella Limit (ARM 17.8.749):

In MAQP #2161-30, NO_X emissions were limited over multiple emitting units for purposes of avoiding PSD. The Temporary Boiler, Boiler #3, Crude Unit #2 Atmospheric Heater H-2101, Crude Unit #2 Vacuum Heater H-2102, Combined Feed Heater H-4101, MHC Reactor Fractionation Feed Heater H-4102, #3 Hydrogen Plant Reformer A, and #3 Hydrogen Plant Reformer B were new units. Boiler #1, Boiler #2, Crude Unit #1 Atmospheric Heater, and Crude Unit #1 Vacuum Heater were included as existing units.

NO_X emissions from the following units, combined, shall not exceed 103.02 tons per year as determined monthly on a rolling 12 month basis, for purposes of PSD avoidance for NO_X associated with the expansion project as permitted in MAQP #2161-30. With exception of Boiler #4 (Natural Gas fired Temporary Boiler) or any unit equipped with NO_X CEMS verified via RATA, NO_X emissions shall be determined utilizing emissions factors determined via monthly portable analyzer results for 12 months, after which, emissions factors shall be determined based on source tests. Fuel flow shall be monitored continuously and heat content of fuel gas determined no less than weekly. The monthly and rolling 12 month sums for the previous month shall be determined and recorded by no later than the 25th of each month. The Temporary Boiler shall be monitored according to Section II, with emissions factors based on source tests. This limit is effective beginning with the first full month following the start of portable analyzer testing. Portable analyzer testing shall begin within 90 days after finalization of MAQP #2161-30 or upon startup of any affected unit, whichever is later.

- Boiler #1
- Boiler #2
- Crude Unit #1 Atmospheric Heater
- Crude Unit #1 Vacuum Heater
- Boiler #3
- Boiler #4 (Temporary Boiler)
- Crude Unit #2 Atmospheric Heater H-2101
- Crude Unit #2 Vacuum Heater H-2102
- Combined Feed Heater H-4101
- MHC Reactor Fractionation Feed Heater H-4102
- #3 Hydrogen Plant Reformer A
- #3 Hydrogen Plant Reformer B

19. MAQP #2161-30 CO Umbrella Limit (ARM 17.8.749):

In MAQP #2161-30, CO emissions were limited over multiple emitting units for purposes of avoiding PSD. The Temporary Boiler, Boiler #3, Crude Unit #2 Atmospheric Heater H-2101, Crude Vacuum Heater H-2102, Combined Feed Heater H-4101, MHC Reactor Fractionation Feed Heater H-4102, #3 Hydrogen Plant Reformer A, and #3 Hydrogen Plant Reformer B were new units. Boiler #1, Boiler #2, Crude Unit #1 Atmospheric Heater, and Crude Unit #1 Vacuum Heater were included as existing units.

CO emissions from the following units, combined, shall not exceed 55.08 tons per year as determined monthly on a rolling 12 month basis, for purposes of PSD avoidance for CO associated with the expansion project as permitted in MAQP #2161-30. With exception of Boiler #4 (Natural Gas fired Temporary Boiler) or any unit equipped with CO CEMS verified via RATA, CO emissions shall be determined utilizing emissions factors determined via monthly portable analyzer results for 12 months, after which, emissions factors shall be determined based on annual source tests. Fuel flow shall be monitored continuously and heat content of fuel gas determined no less than weekly. The monthly and rolling 12 month sums for the previous month shall be determined and recorded by no later than the 25th of each month. The Temporary Boiler shall be monitored according to Section II, with emissions factors based on source tests. This limit is effective beginning with the first full month following the start of portable analyzer testing. Portable analyzer testing shall begin within 90 days after finalization of MAQP #2161-30 or upon startup of an affected unit, whichever is later.

- Boiler #1
- Boiler #2
- Crude Unit #1 Atmospheric Heater
- Crude Unit #1 Vacuum Heater
- Boiler #3
- Boiler #4 (Temporary Boiler)
- Crude Unit #2 Atmospheric Heater H-2101
- Crude Unit #2 Vacuum Heater H-2102
- Combined Feed Heater H-4101
- MHC Reactor Fractionation Feed Heater H-4102
- #3 Hydrogen Plant Reformer A
- #3 Hydrogen Plant Reformer B

20. Sour Water Stripper Ammonia Combustor:

a. NO_X emissions from the Ammonia Combustor shall not exceed 61 ppmv @ 3% O_2 on a 3-hr average basis. (ARM 17.8.752).

b. NO_X emissions from the Ammonia Combustor shall not exceed 2.79 tons per year as determined monthly on a rolling 12 month basis (ARM 17.8.749).

c. CO emissions from the ammonia combustor shall not exceed 9.01 tons per year as determined monthly on a rolling 12 month basis (ARM 17.8.749).

d. Calumet shall comply with the SO_2 or H_2S emissions limitation for fuel gas combustion devices as provided in 40 CFR 60 Subpart Ja (ARM 17.8.752).

e. Ammonia emissions shall not exceed 10 ppmvd at 3% O_2 on a 1-hr average basis (ARM 17.8.749, ARM 17.8.752).

f. Calumet shall comply with the fuel gas combustion device requirements of 40 CFR 60 Subpart Ja as applicable to the Ammonia Combustor (ARM 17.8.340 and 40 CFR 60 Subpart Ja).

D. Testing and Monitoring Requirements:

1. Refinery Fuel Gas Combustion Devices

a. Calumet shall install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases in accordance with the requirements of 40 CFR 60.11, 60.13, and 60 Appendix A, and the applicable performance specification test of 40 CFR 60 Appendices B and F, in order to demonstrate compliance with the limit in Section II.B.20 (Consent Decree, ARM 17.8.340 and 40 CFR 60, Subpart J).

b. Calumet shall install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases in accordance with the requirements of 40 CFR 60.11, 60.13, and 60 Appendix A, and the applicable performance specification test of 40 CFR 60 Appendices B and F, in order to demonstrate compliance with the limit in Section II.B.21 (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

c. Calumet shall install, operate, calibrate and maintain on each applicable heater, an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_x emissions into the atmosphere pursuant to 40 CFR 60, Subpart Ja or complete biennial performance tests in accordance with 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

d. By July 1, 2008, Calumet shall install and operate an SO_2 and O_2 CEMS and a volumetric flow rate monitor on the stack for the #1 and #2 Boilers, to be used as the primary analytical instrument to determine compliance with state and federal SO_2 requirements. By July 1, 2008, Calumet shall initially certify the #1 and #2 Boiler SO_2/O_2 CEMS and the volumetric flow rate monitor in accordance with 40 CFR Part 60, Performance Specifications 2 and 3 and 6. After initial certification, Calumet shall conduct annual Relative Accuracy Test Audits (RATA) of the #1 and #2 Boiler SO_2/O_2 CEMS, and volumetric flow rate monitoring conformance with 40 CFR 60, Appendix F. After initial certification, Calumet shall also continue to implement all of the requirements of 40 CFR 60.13 and 40 CFR 60, Appendices B and F for the #1 and #2 Boilers SO_2/O_2 CEMS and flow rate monitor. (May 2008 Administrative Order on Consent and ARM 17.8.749).

e. Calumet shall install and operate an SO_2 and O_2 CEMS, and a volumetric flow rate monitor on the stack for the Boiler #3, to be used as the primary analytical instrument to determine compliance with state and federal SO_2 requirements. Calumet shall initially certify the Boiler #3 SO_2/O_2 CEMS, and the volumetric flow rate monitor in accordance with 40 CFR 60, Performance Specifications 2, 3 and 6. After initial certification, Calumet shall conduct annual RATA of the Boiler #3 SO_2/O_2 CEMS and the volumetric flow rate monitor in conformance with 40 CFR 60, Appendix F. After initial certification, Calumet shall also continue to implement all of the requirements of 40 CFR 60.13 and 40 CFR 60, Appendices B and F for the Boiler #3 SO_2/O_2 CEMS. (ARM 17.8.749).

2. Boiler #4 (Temporary Boiler)

   a. Within 90 days of finalization of MAQP #2161-30, Calumet shall test Boiler #4 for CO and NO_X concurrently, to monitor compliance with Section II.C.2.c and II.C.2.d. An emissions factor in the form of lb/MMBtu shall be determined during the test. Thereafter, Calumet shall test for NO_X and CO, concurrently, as required or as requested by the Department in writing. (ARM 17.8.105 and ARM 17.8.749).

   b. Calumet shall operate and maintain fuel flow monitoring to continuously monitor and record fuel flow to Boiler #4. (ARM 17.8.749).

   c. Calumet shall determine, on a higher heating value basis, the Btu/scf of the natural gas, or alternatively, utilize information available from and provided by the pipeline quality natural gas provider. If Calumet determines the Btu/scf of the pipeline quality natural gas, Calumet shall determine the heating value no less than once per calendar quarter. (AMR 17.8.749).

3. Units Subject to the NO_X Umbrella Limitation of Section II.

   a. Each unit subject to the NO_X umbrella limitation and not equipped with validated (RATA conducted) CEMS meeting 40 CFR 60 Subpart A and Ja requirements, shall have annual Method 7E source tests (or testing as approved by the Department), with the first source test to be conducted no later than 12 months after finalization of MAQP #2161-30. All testing shall be conducted concurrently with CO testing. Units equipped with NO_X CEMS shall conduct a RATA as required. Emissions factors in units of lb/MMBtu shall be determined from the most recent emissions testing (portable analyzer test, source test, or performance test (i.e. RATA testing), as applicable). (ARM 17.8.749).

   b. For any refinery fuel gas fired units subject to the NO_X umbrella limit in which a NO_X CEMS verified via a RATA is not in place, Calumet shall, at least once every calendar month, conduct concurrent NO_X and CO monitoring utilizing a portable analyzer and submit the results in a format as provided by Attachment 2 on a quarterly basis (within 45 days of the end of each calendar quarter). Such monitoring must begin no later than 90 days after finalization of MAQP #2161-30, and shall be conducted for no less than 12 consecutive months following finalization of MAQP #2161-30. Any subsequent source test indicating noncompliance with any NO_X or CO limit shall reinstate this requirement, until no less than 4 quarters of compliance is again achieved. Emissions factors in units of lb/MMBtu shall be determined from the most recent emissions testing (portable analyzer test, source test or performance test, as applicable.) (ARM 17.8.749).

c. A source testing protocol meeting the minimum requirements of Attachment 2 shall be submitted to the Department no later than 30 days after finalization of MAQP #2161-30, and such revisions as may be required submitted such that an approved source test protocol is in place within 60 days after finalization of MAQP #2161-30. Calumet shall conduct portable analyzer testing as required by the Department. (ARM 17.8.749).

d. Portable analyzer testing shall not be required in any month in which source testing or performance testing is performed (ARM 17.8.749).

4. Units Subject to CO Umbrella Limitation of Section II.

a. For all units subject to the CO Umbrella Limitation of Section II. in which a validated CO CEMS is not utilized, Calumet shall test for CO currently with testing for NO_X (ARM 17.8.749). For any units equipped with NO_X CEMS but no CO CEMS, CO testing concurrent with NO_X RATA Testing is acceptable. Units equipped with CO CEMS shall conduct a RATA as required, and determine lb/MMBtu emissions factors during the RATA testing. (ARM 17.8.749).

b. For any refinery fuel gas fired units subject to the CO umbrella limit in which a CO CEMS verified via a RATA is not utilized, Calumet shall, at least once every calendar month, conduct concurrent NO_X and CO monitoring utilizing a portable analyzer and submit the results in a format as provided by Attachment 2 on a quarterly basis (within 45 days of the end of each calendar quarter). Such monitoring must begin no later than 90 days after finalization of MAQP #2161-30, and shall be conducted for no less than 12 consecutive months following finalization of MAQP #2161-30. Any subsequent source test indicating noncompliance with any NO_X or CO limit shall reinstate this requirement, until no less than 4 quarters of compliance is again achieved. (ARM 17.8.749).

c. A source testing protocol meeting the minimum requirements of Attachment 2 shall be submitted to the Department no later than 30 days after finalization of MAQP #2161-30, and such revisions as may be required submitted such that an approved source test protocol is in place within 60 days after finalization of MAQP #2161-30. Calumet shall conduct portable analyzer testing as required by the Department. (ARM 17.8.749).

5. Crude Heater #2 H-2101, Mild Hydrocracker Heater H-4101, and #3 Hydrogen Plant Reformer Heaters H-3815A and H3815B shall be equipped with NO_X CEMS in compliance with 40 CFR 60 Subpart A and Ja by no later than June 30, 2018. (ARM 17.8.749).

6. Ammonia Combustor

   a. NO_X emissions shall be monitored no less than once per calendar month utilizing a portable analyzer to determine NO_X emissions. Such monitoring shall begin no later than 90 days after startup of the ammonia combustor. A source testing protocol meeting the minimum requirements of Attachment 2 shall be submitted to the Department no later than 30 days after finalization of MAQP #2161-30, and such revisions as may be required submitted such that an approved source test protocol is in place within 60 days after startup. Such portable analyzer testing shall continue on a monthly basis for 12 consecutive months. Thereafter, Calumet shall test the ammonia combustor for NO_X concurrently with CO at least annually via Method 7E or as otherwise approved by the Department. (ARM 17.8.749).

   b. CO emissions shall be monitored no less than once per month utilizing a portable analyzer to determine CO emissions. Such monitoring shall begin no later than 90 days after startup of the ammonia combustor. A source testing protocol meeting the minimum requirements of Attachment 2 shall be submitted to the Department no later than 30 days after finalization of MAQP #2161-30, and such revisions as may be required submitted such that an approved source test protocol is in place within 60 days after startup. Such portable analyzer testing shall continue on a monthly basis for 12 consecutive months. Thereafter, Calumet shall test the ammonia combustor for CO concurrently with NO_X at least annually via Method 10 or as otherwise approved by the Department. (ARM 17.8.749).

   c. Calumet shall monitor SO_2 emissions from the ammonia combustor in accord with the 40 CFR 60 Subpart Ja monitoring requirements (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja).

   d. Calumet shall perform source testing for NH_3 utilizing methodology as agreed in writing by Calumet and the Department, within 180 days of startup, and thereafter as required by the department (ARM 17.8.749).

   e. Calumet shall maintain records of ammonia combustor run time, noting any periods of time in which the ammonia combustor is nonoperational with a precision of no less than an hourly basis (ARM 17.8.749 and ARM 17.8.752(2)). Calumet shall also monitor the amount of natural gas and amount of ammonia enriched fuel gas combusted. Such records shall be utilized to determine mass emissions rates (ARM 17.8.749).

7. SWSOH

   a. Calumet shall comply with the H_2S/SO_2 monitoring requirements contained in 40 CFR 60, Subpart J (Boilers #1 and #2) or Ja (Boiler #3), during all times when the HTU SWSOH is incinerated in the Boilers. Calumet shall conduct either H_2S monitoring of the SWSOH stream to demonstrate compliance with the limit in Section II.B.16, or SO_2 stack monitoring for the #1, #2 and #3 Boilers to demonstrate compliance with 20 ppm (dry basis, zero percent excess air) SO_2, as approved by the Department, in writing (Consent Decree, ARM 17.8.340, 40 CFR 60, Subpart J (Boilers #1 and #2), and/or 40 CFR 60, Subpart Ja (Boiler #3)).

8. Calumet shall install and use the following continuous emission monitoring system (CEMS) on the FCCU:

   a. SO_2 and O_2 (Consent Decree)

   b. NO_x and O_2 (Consent Decree)

   c. CO and O_2 (Consent Decree, ARM 17.8.342 and 40 CFR 63, Subpart UUU)

   d. Opacity (ARM 17.8.340 and 40 CFR 60, Subpart J, and ARM 17.8.342 and 40 CFR 63, Subpart UUU)

9. Calumet shall install, certify, calibrate, maintain and operate the above-mentioned SWSOH and FCCU CEMS in accordance with the requirements of 40 CFR 60.11, 60.13, and 60 Appendix A, and the applicable performance specification test of 40 CFR 60 Appendices B and F and 40 CFR 60, Subpart J. These CEMS are a means for demonstrating compliance with the relevant emission limits (Consent Decree).

10. For both the gasoline truck loading rack and the gasoline railcar loading rack, Calumet shall install, calibrate, certify, operate and maintain a thermocouple with an associated recorder as a continuous parameter monitoring system (CPMS). A CPMS shall be located in each VCU firebox or in the ductwork immediately downstream from the firebox in a position before any substantial heat exchange occurs in accordance with 40 CFR 63.427, in order to demonstrate compliance with 40 CFR 63, Subpart R. Calumet shall operate the VCUs in a manner not to go below the operating parameter values established using the procedures in 40 CFR 63.425 (ARM 17.8.342 and 40 CFR 63, Subpart CC).

11. Calumet shall operate and maintain instrumentation for continuously monitoring the volumetric flow and sulfur content to the flare system (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

12. The FCCU shall be tested for CO and SO_2 and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section II.C.13.c and d. The testing shall occur annually or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.106).

13. Compliance with the FCCU PM emission limit in Section II.C.13.a shall be demonstrated by conducting a 3-hour performance test representative of normal operating conditions for PM emissions by December 31 of each calendar year. If any performance test undertaken pursuant this section is not representative of normal operating conditions, Calumet shall conduct a subsequent performance test representative of normal operating conditions by no later than 90 days after the test that was not representative (Consent Decree).

14. All fuel combustion devices in the #2 Crude Unit shall be initially tested for NOx and subject to the applicable performance testing requirements of 40 CFR 60, Subpart Ja and applicable testing requirements of Consent Decree (ARM 17.8.340 and Consent Decree).

15. The owner or operator of each applicable fuel combustion device and flare subject to 40 CFR 60, Subpart Ja shall demonstrate initial compliance with the applicable emission limit in §60.102a according to the requirements of §60.8.

16. Calumet shall comply with all test methods and procedures as specified by 40 CFR 63.425(a) through (c), and 63.425(e) through (h). This shall apply to, but not be limited to, the gasoline and distillate truck loading rack, the gasoline railcar loading rack, the vapor processing systems, and all gasoline equipment.

17. The gasoline truck loading rack VCU shall be tested for total organic compounds and compliance demonstrated with the emission limitation contained in Section II.C.11 on an every 5-year basis or according to another testing/monitoring schedule as may be approved by the Department. Calumet shall perform the test methods and procedures as specified in 40 CFR 63.425 (ARM 17.8.105 and 17.8.342).

18. The gasoline railcar loading rack VCU shall be initially tested for total organic compounds and compliance demonstrated with the emission limitation contained in Section II.C.12.a within 180 days of initial startup. Additional testing shall occur on an every 5-year basis or according to another testing/monitoring schedule as may be approved by the Department. Calumet shall perform the test methods and procedures as specified in 40 CFR 63.425 (ARM 17.8.105 and 17.8.342).

19. The gasoline railcar loading VCU shall be initially tested for CO and NOx, concurrently, and compliance demonstrated with the emission limitations contained in Section II.C.12.b and c within 180 days of initial startup (ARM 17.8.105).

20. Fuel flow rates, production information, and any other data the Department believes is necessary shall be recorded during the performance of source tests (ARM 17.8.749).

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

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

E. Compliance Determination:

1. Facility-wide Refinery:

   a. Compliance with the plant-wide SO_2 emission limitations contained in Section II.C.1.a shall be determined based on data taken from the refinery fuel gas H_2S monitoring systems required by 40 CFR 60, Subpart J or Ja, in conjunction with metered refinery fuel gas usage (including SWSOH, if appropriate), data from the FCCU, the #1 and #2 Boiler SO_2 CEMS, the Boiler #3 SO_2 CEMS and stack testing data.

b. Compliance with the plant-wide CO emission limitations contained in Section II.C.1.b shall be determined based on data from the FCCU CO CEMS and emission factors developed from stack tests of the Boiler #1, Boiler #2, Boiler #3, FCCU, product loading VCUs, and any other stack tests conducted.

c. By the 25th day of each month, Calumet shall calculate and record the monthly and rolling 12 month sum of NO_X emissions from each unit subject to the NO_X umbrella limitations for the previous month. Calumet shall also calculate and record, by the 25th of each month, the total monthly and rolling 12 month sum of emissions for the units combined for the previous 12 months. (ARM 17.8.749).

d. By the 25th day of each month, Calumet shall calculate and record the monthly and rolling 12 month sum of CO emissions from each unit subject to the CO umbrella limitations for the previous month. Calumet shall also calculate and record, by the 25th of each month, the total monthly and rolling 12 month sum of emissions for the units combined for the previous 12 months. (ARM 17.8.749).

e. By the 25th day of each month, Calumet shall calculate and record the monthly and rolling 12 month sum of NO_X and CO emissions from the ammonia combustor for the previous month. (ARM 17.8.749).

2. Boilers #1 and #2

a. Compliance with Boilers #1 and #2 SO_2 emission limitations contained in Section II.C.3.a shall be based on the data from the SO_2/O_2 CEMS (May 2008 Administrative Order on Consent and ARM 17.8.749).

b. In the event that SO_2/O_2 CEMS or volumetric flow monitor is not operational, Calumet must (ARM 17.8.749):

i. notify the Department of the problem within 24 hours (by phone) followed by written notification within 7 days;

ii. continue to monitor using the H_2S CEMS at the fuel gas drum (pre-combustion);

iii. route all SWSOH to the NaHS unit;

iv. repair and/or replace the SO_2/O_2 CEMS equipment and continue to monitor compliance as required in Section II.F; and

v. notify the Department within 24-hours when the SO_2/O_2 CEMS is back on-line.

Compliance with the #1 and #2 Boiler CO emission limits contained in Section II.C.3.c shall be determined through compliance source testing and by using the actual fuel burning rates and the emission factors developed from the most recent compliance source test (ARM 17.8.749).

3. Boiler #3

   a. Compliance with the Boiler #3 SO_2 emission limitations contained in Section II.C.4 shall be based on the data from the SO_2/O_2 CEMS (ARM 17.8.749).

   b. In the event that SO_2/O_2 CEMS is not operational, Calumet must (ARM 17.8.749):

      i. notify the Department of the problem within 24 hours (by phone) followed by written notification within 7 days;

      ii. continue to monitor using the H_2S CEMS at the fuel gas drum (pre-combustion);

      iii. route all SWSOH to the NaHS unit;

      iv. repair and/or replace the SO_2/O_2 CEMS equipment and continue to monitor compliance as required in Section II.F.3;

      v. notify the Department within 24 hours when the SO_2/O_2 CEMS is back on-line.

   c. Calumet shall monitor NO_X emissions from Boiler #3 in accordance with 40 CFR 60 Subpart Ja. (ARM 17.8.340 and 40 CFR 60 Subpart Ja, ARM 17.8.749)

   d. Compliance with the Boiler #3 CO emission limits in Section II.C.4 shall be demonstrated through compliance source testing and by using the actual fuel burning rates and the emission factors developed from the most recent compliance source test (ARM 17.8.749).

4. Diesel/Gas Oil HDS Heater

   Compliance determinations for NO_x and CO emission limits for the diesel/gas oil HDS heater shall be based upon source testing and actual fuel burning rates and emission factors developed from the most recent compliance source test.

5. Hydrogen Plant(s) - Reformer Heaters

   a. Compliance determinations for NOx and CO emission limits for Hydrogen Plant #1 reformer heater shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test.

   b. Compliance with NO_x and SO_2 emission limits for Hydrogen Plant #3 reformer heaters (H-31A and H-31B) shall be conducted in accordance with monitoring and testing requirements of 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

c. Calumet shall submit all reporting and recordkeeping in accordance with the Greenhouse Gas Reporting Rule to demonstrate compliance with the CO_2e emission limits (ARM 17.8.749).

6. Gasoline Truck Loading Rack VCU

Compliance determinations for VOC, NO_x and CO emission limits for the gasoline truck loading rack VCU shall be based upon the most recent compliance source test as well as compliance with the designated operating parameter value using the thermocouple and recorder.

7. Gasoline Railcar Loading Rack VCU

Compliance determinations for VOC, NO_x and CO emission limits for the gasoline railcar loading rack VCU shall be based upon the most recent compliance source test as well as compliance with the designated operating parameter value using the thermocouple and recorder.

8. FCCU

Compliance determinations for the PM emission limit under Section II.C.13.a will be based on the annual source test conducted under Section II.E. Compliance determinations for CO, SO_2 and NO_x emission limits under Section II.C.13 will be based on the data from CEMS as well as the annual source test conducted under Section II.E.

9. #2 Crude Unit and MHC process heaters (H-2101, H-2102, H-4101, H-4102)

Compliance monitoring with NSPS Ja NOx and SO_2 emission limits for these heaters shall be conducted in accordance with monitoring and testing requirements of 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

10. Flare System (Primary Flare #1 and Secondary Flare #2)

Calumet shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in the fuel gases before being burned in any fuel combustion device or flare. The H_2S monitor shall be installed, operated and maintained in accordance with Performance Specification 7 of Appendix B to Part 60 (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

11. Compliance with the opacity limitations shall be determined according to 40 CFR 60, Appendix A, and Method 9 Visual Determination of Opacity of Emissions from Stationary Sources.

F. Reporting and Recordkeeping Requirements:

1. Plant-wide Refinery

Calumet shall provide quarterly emission reports to demonstrate compliance with Section II.C.1.a using data required in Section II.F.1.a. The quarterly report shall include the following (ARM 17.8.749):

a. Facility-wide SO_2 emission estimates for each month of the quarter, including:

   i. Refinery fuel gas: daily H_2S monitoring data and refinery fuel gas usage;

   ii. SWSOH: daily H_2S and SWSOH combustion amount, or SO_2 monitoring data from the #1 & #2 Boiler stack;

   iii. SO_2 CEMS Data from FCCU, Boiler #1, Boiler #2, and Boiler #3 converted to daily mass emissions;

b. Compliance source test data used to update emission factors, conducted during the reporting period;

c. Identification of any periods of excess emissions or other excursions during the reporting period; and

d. Monitoring downtime that occurred during the reporting period.

2. Boilers #1 and #2

Calumet shall provide quarterly emission reports to demonstrate compliance with Section II.C.3 using data required in Section II.F.2. The quarterly report shall include the following (ARM 17.8.749):

a. SO_2 emission estimates for #1 and #2 Boilers, for each month of the quarter, including:

   i. Hourly SO_2 CEMS data for the reporting period;

   ii. Fuel gas H_2S analyzer data for the reporting the period;

   iii. SWSOH – either the daily H_2S concentration and SWSOH combustion amount of the HTU SWSOH, or the #1 and #2 Boiler stack SO_2 concentration on a daily basis;

b. NO_x emission estimates for each month of the quarter. The NO_x emission rates shall be reported as an hourly average and a monthly total;

c. CO emission estimates for the #1 and #2 Boilers, for each month of the quarter. The CO emission rate shall be reported as an hourly average;

d. Operating times for #1 and #2 Boilers and the HTU SWS unit during the reporting period;

e. Compliance source test data used to update emission factors, conducted during the reporting period;

f. Calumet shall maintain records of daily fuel usage (in MMscf/yr) in the #1 and # 2 Boilers. The fuel usage shall be reported annually for each Boiler based on a 12-month total (ARM 17.8.749);

g. Identification of any periods of excess emissions or other excursions during the reporting period; and

h. Monitoring downtime that occurred during the reporting period.

3. Boiler #3

Calumet shall provide quarterly emission reports to demonstrate compliance with Section II.C.4 using data required in Section II.F.3. The quarterly report shall include the following (ARM 17.8.749):

a. SO_2 emission estimates for the Boiler #3, for each month of the quarter, including:

   i. Hourly SO_2/O_2 CEMS data for the reporting period;

   ii. Fuel gas H_2S analyzer data for the reporting the data;

   iii. SWSOH – either the daily H_2S concentration and SWSOH combustion amount of the HTU SWSOH, or the Boiler #3 stack SO_2 concentration on a daily basis;

b. NO_x emission estimates for each month of the quarter. The NO_x emission rates shall be reported as an hourly average;

c. CO emission estimates for the Boiler #3, for each month of the quarter. The CO emission rate shall be reported as an hourly average;

d. Operating times for Boiler #3 and the HTU SWSOH unit during the reporting period;

e. Compliance source test data used to update emission factors, conducted during the reporting period;

f. Identification of any periods of excess emissions or other excursions during the reporting period; and

g. Monitoring downtime that occurred during the reporting period.

4. Gasoline Truck Loading Rack VCU

Calumet shall comply with all recordkeeping and reporting requirements, as applicable, of 40 CFR 63.654 and the referenced provisions in 40 CFR 63, Subpart R (ARM 17.8.342 and 40 CFR 63, Subpart CC).

5. Gasoline Railcar Loading Rack VCU

Calumet shall comply with all recordkeeping and reporting requirements, as applicable, of 40 CFR 63.654 and the referenced provisions in 40 CFR 63, Subpart R (ARM 17.8.342 and 40 CFR 63, Subpart CC).

6. FCCU

   Calumet shall provide quarterly emission reports to demonstrate compliance with Section II.C.13 using data required in Section II.F.8. The quarterly report shall include the following (ARM 17.8.749):

   a. Emission estimates for NO_x, SO_2 and CO, for each month of the quarter;

   b. Daily SO_2 CEMS data for the reporting period;

   c. Hourly NO_x and CO CEMS data for the reporting period;

   d. Operating times for the FCCU during the reporting period;

   e. Identification of any periods of excess emissions or other excursions during the reporting period; and

   f. Monitoring downtime that occurred during the reporting period.

7. All Emission Reports shall be submitted within 45 days following the end of the calendar quarter (ARM 17.8.749).

8. Calumet shall maintain a file of all measurements from all CEMS and H_2S monitors, including, but not limited to: compliance data; performance testing measurements; all flow rate meter performance evaluations; all flow rate meter calibrations, checks, and audits. Adjustments and maintenance performed on these systems or devices shall be recorded in a permanent form suitable for inspection. The file shall be retained on site for at least 5-years following the date of such measurements and reports. Calumet shall supply these records to the Department upon request (ARM 17.8.749).

9. Calumet shall report monthly and rolling 12 month sums for each unit under the NO_X and CO Umbrella limitations of Sections II.C.14 and II.C.15, on a quarterly basis. The report shall include monthly and rolling 12 month sums for each unit, and as a sum of all units. (ARM 17.8.749).

10. Calumet shall report monthly and rolling 12 month sums of NO_X and CO emissions from the ammonia combustor on a quarterly basis. (ARM 17.8.749)

G. Operational Reporting Requirements

1. Calumet shall supply the Department with annual production information for all emission points, as required, by the Department in the annual Emission Inventory request. The request will include, but is not limited to, all sources of emissions identified in the Emission Inventory contained in the Permit Analysis and sources identified in Section I of this permit.

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

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

3. All records compiled in accordance with this permit must be maintained by Calumet as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

H. Notification Requirements

1. Calumet shall provide the Department with written notification of the following dates within the specified time periods (ARM 17.8.749):

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

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

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

2. Tank Construction

   Calumet shall provide notification of the actual start-up date of tanks #122, #123, #52, #49, #47, #48, #50, #102 within 15 days after the actual start-up of the unit.

3. #2 Crude Unit - Expansion Project

   a. Calumet shall provide notification of start of construction for each unit within 30 days after actual construction has begun;

   b. Calumet shall provide notification of the actual start-up date of each unit within 15 days after the actual start-up of the unit;

c. Calumet shall provide notification of the start of construction of new and modified tanks associated with the #2 Crude Unit.

4. Boiler #4 (Temporary Boiler)

Calumet shall provide notification of the actual start-up date of the Temporary Boiler within 15 days after the actual start-up of the unit. (ARM 17.8.749).

5. Ammonia Combustor

Calumet shall provide notification of the actual start-up date of the Ammonia Combustor within 15 days after the actual start-up of the unit. (ARM 17.8.749).

I. Ambient Monitoring

Calumet shall conduct ambient air monitoring as described in Attachment 1.

SECTION III: General Conditions

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

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

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

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

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

Department’s decision on the application is final 16 days after the Department’s decision is made.

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

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

H. Duration of Permit – Construction or installation must begin or contractual obligations entered into that would constitute substantial loss within 18 months of permit issuance and proceed with due diligence until the project is complete or the permit shall expire (ARM 17.8.762).

Summary of Attachments

Attachment 1	AMBIENT AIR MONITORING PLAN
Attachment 2	PORTABLE ELECTROCHEMICAL (EC) ANALYZER TESTING FOR NO_X AND CO UMBRELLA LIMIT MONITORING

ATTACHMENT 1

AMBIENT AIR MONITORING PLAN
Calumet Montana Refining, LLC (Calumet)

1. This Ambient Air Monitoring Plan applies to Calumet's crude oil refinery located at 1900 10th Street North East, in Great Falls, Montana. The Department may modify the requirements of this monitoring plan. All requirements of this plan are considered conditions of the permit.

2. The requirements of this attachment shall take effect within 30 days of permit issuance, unless otherwise approved in writing by the Department.

3. Calumet shall operate and maintain one air monitoring site northeast of the refinery. The exact location of the monitoring site must be approved by the Department and meet all the siting requirements contained in the Montana Quality Assurance Manual, including revisions, the EPA Quality Assurance Manual, including revisions, and 40 CFR Part 58, or any other requirements specified by the Department.

4. Calumet shall submit a topographic map to the Department identifying Universal Transverse Mercator (UTM) coordinates, air monitoring site locations in relation to the facility, and the general area present.

5. Within 30 days prior to any changes of the location of the ambient monitors, Calumet shall submit a topographic map to the Department identifying UTM coordinates, air monitoring site locations in relation to the facility, and the general area present.

6. Calumet shall continue air monitoring for at least 2 years after installation of the monitor described in Section 2 above. The Department will review the air monitoring data and the Department will determine if continued monitoring or additional monitoring is warranted. The Department may require continued air monitoring to track long-term impacts of emissions from the facility or require additional ambient air monitoring or analyses if any changes take place in regard to quality and/or quantity of emissions or the area of impact from the emissions.

7. Calumet shall monitor the following parameters at the site and frequencies described below:

AIRS # 30-013-2001 Site Name – Race Track Site

UTM Coordinates	Code & Parameter	Frequency
Zone 12	42401 SO_2[1]	Continuous
N 5263700	61101 Wind Speed and Direction	"
E 478600	61106 Standard Deviation of Wind Direction (sigma theta)	"

[1]SO_2= sulfur dioxide

8. Data recovery for all parameters shall be at least 80% computed on a quarterly and annual basis. The Department may require continued monitoring if this condition is not met. (Data recovery = (Number of data points collected in evaluation period)/(number of scheduled data points in evaluation period)*(100%)).

9. Any ambient air monitoring changes proposed by Calumet must be approved, in writing, by the Department.

10. Calumet shall utilize air monitoring and Quality Assurance (QA) procedures that are equal to or exceed the requirements described in the Montana Quality Assurance Manual, including revisions, the EPA Quality Assurance Manual, including revisions, 40 CFR Parts 50 and 58, and any other requirements specified by the Department.

11. Calumet shall submit two hard copies of quarterly data reports within 45 days after the end of the calendar quarter and two hard copies of the annual data report within 90 days after the end of the calendar year.

12. The quarterly data submittals shall consist of a hard copy narrative data summary and a digital submittal of all data points in AIRS batch code format. The electronic data must be submitted to the Air Monitoring Section as digital text files readable by an office personal computer (PC) with a Windows operating system.

    The narrative data hard copy summary must be submitted to the Air Compliance Section and shall include:

    a. A hard copy of the individual data points,

    b. The first and second highest 24-hour rolling and block concentrations for SO_2,

    c. The first and second highest 3-hour concentrations for SO_2,

    d. The first and second highest hourly concentrations for SO_2,

    e. The quarterly and monthly wind roses,

    f. A summary of data completeness,

    g. A summary of the reasons for missing data,

    h. A precision data summary,

    i. A summary of any ambient air standard exceedances, and

    j. Quality Assurance/Quality Control (QA/QC) information such as zero/span/precision, calibration, audit forms, and standards certifications.

13. The annual data report shall consist of a narrative data summary. The narrative data hard copy summary must be submitted to the Air Compliance Section and shall include:

    a. A topographic map of appropriate scale with UTM coordinates and a true north arrow showing the air monitoring site location in relation to the refinery and the general area,

    b. The annual average concentration for SO_2;

    c. The year's four highest 24-hour rolling and block concentrations for SO_2,

    d. The year's four highest 3-hour concentrations for SO_2,

    e. The year's four highest hourly SO_2 concentrations,

    f. The annual wind rose,

    g. A summary of any ambient air standard exceedances, and

    h. An annual summary of data completeness.

14. All records compiled in accordance with this Attachment must be maintained by Calumet as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

15. The Department may audit (or may require Calumet to contract with an independent firm to audit) the air monitoring network, the laboratory performing associated analyses, and any data handling procedures at unspecified times.

16. The hard copy reports should be sent to:
    Department of Environmental Quality – Air Quality Bureau
    Attention: Field Services Section Supervisor

17. The electronic data from the quarterly monitoring shall be sent to:
    Department of Environmental Quality – Air Quality Bureau
    Attention: Research & Monitoring Section Supervisor

ATTACHMENT 2

Portable Electrochemical (EC) Analyzer Testing for NO_X and CO Umbrella Limit Monitoring

Calumet shall submit a source testing protocol, intended to be applicable for 5 years from the acceptance date, regarding details of the portable testing plan. The following are guidelines which outline the minimum requirements to be met in such submittal.

Analyzer Apparatus

1. Use any measurement system that meets the performance and design specifications of this guidance. The sampling system should maintain the gas sample at conditions that will prevent condensation in the lines or when it contacts the EC cells. Some of the components of an appropriate measurement system are described below.

2. The sample probe and sample line should be made of glass, stainless steel or other non-reactive material and should be designed to prevent condensation.

3. The calibration assembly should introduce calibration gases at ambient pressure to the sample probe during calibration checks. The assembly should be designed such that only the calibration gases are processed and that the calibration gases flow through all the filters in the sampling line.

4. The moisture removal system should be used to remove condensate from the sample gas while maintaining minimal contact between the condensate and the sample gases.

5. Particulate filters should be utilized before the inlet of the EC analyzer to prevent accumulation of particulate material in the measurement system and to extend the useful life of the EC analyzer. All filters should be fabricated of materials that are non-reactive to the gases being sampled.

6. The sample pump should be a leak-free pump that will transport the sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If upstream of the EC cells, the pump should be constructed of material that is non-reactive to the gases being sampled.

7. The sample flow rate should not vary by more than 10% throughout the calibration, testing, and drift check.

8. Interference gas scrubbers should be checked and replenished in accordance with the manufacturer's recommendations. EC analyzers should have a means to determine when the agent is depleted.

9. A data recorder should be used for recording the EC analyzer data.

EC Analyzer Calibration and Testing Specifications:

1. For purposes of testing for submission to the Department, all combustion equipment shall be tested "as-found." No tuning or maintenance for the purpose of lowering tested emissions is allowed within 24 hours prior to testing.

2. Each EC analyzer should be certified by the manufacturer at least once per year unless waived by the Department. Assemble the measurement system by following the manufacturer's recommended procedures for preparing and preconditioning the EC analyzer. Ensure the system has no leaks and verify that the gas-scrubbing agent is not depleted. When an EC cell is replaced, the EC analyzer should be re-calibrated.

3. Calibration of the EC analyzer should be done using certified calibration gases (EPA Protocol gases). Fresh air, free from ambient CO and NO_X, is permitted for O_2 calibration (20.9% O_2), and as a zero gas for CO and NO_X. Calibration gases for NO, NO_2, and CO should be chosen so that the concentration of the calibration gas is between 20% and 125% of the range of concentrations of the EC analyzer cell for each pollutant. Alternatively, calibration gases should not exceed 200% of the anticipated concentration expected from the emission unit being tested. If the measured concentration exceeds 125% of the span of the EC analyzer, at any time during the sampling run, that test run should be considered invalid. For NO_2 concentrations below 10% of the total NO_X concentration, NO_2 does not have to be measured directly and calibration of the EC analyzer for NO_2 is not required.

4. Inject each calibration gas into the EC analyzer and record the start time, response time, and concentrations. Gases should be injected through the entire sample handling system. All EC analyzer output responses should be recorded at least once per minute. The response time is the time it takes for the EC analyzer to get a steady response from a calibration gas after injecting the calibration gas into the measurement system. Actual measurements should not be averaged until the after the response time of the measurement system. After each calibration gas run, the EC analyzer should be refreshed with fresh air, free from CO, NO_X, and other pollutants. Repeat these steps for each calibration gas.

5. For the EC analyzer O_2 cell calibration, the minimum detectable limit should be 0.3%. For the EC analyzer NO_X and CO cells, the minimum detectable limit should be 2% of the calibration gas or 2 ppm whichever is less restrictive. If an invalid calibration is exhibited, corrective action should be taken and the EC analyzer calibration check should be repeated until an acceptable EC analyzer performance is achieved.

6. Calculate the mean of the readings from the EC analyzer for each calibration gas. The average calculated EC analyzer response error, for each calibration gas, should not exceed ±5% of the calibration gas concentration. The maximum allowable deviation of any single reading, after the response time and prior to the refresh period, should not exceed ±2% of the average calculated EC analyzer response. *For Example: For a calibration gas with a concentration of 100 ppm, the calibration gas check should be considered valid only if the average of the measured concentrations for that calibration gas are within 5 ppm of 100 ppm, i.e., 95 to 105 ppm, and if the maximum deviation of any single measurement comprising that average is less than 2% or approximately 2 ppm.*

7. During calibration an interference check should be performed. During the calibration check of a single gas species (e.g., NO & NO_2), record the response displayed by the other EC cells (i.e., CO & NO). Record the interference response for each EC cell to each calibration gas. The CO, NO, and NO_2 interference response should not exceed 5% of the calibration gas concentration. EC analyzers that have been verified for interference response using an interference scrubber are considered to be in compliance with this interference check specification when the interference scrubber is replenished per manufacturer's specifications.

The potential for interference from other flue gas constituents should be reviewed with the EC analyzer manufacturer based on site-specific data.

8. A post-test calibration check should be performed in the same manner as the pre-test calibration after each emissions unit test. If the post-test calibration checks do not meet the required specifications, all test data for that emissions unit should be considered null and void and re-calibration and re-testing should be conducted. To prevent loss of data, the drift of the analyzer should be determined after each measurement cycle. This should be done by performing a calibration check after each measurement cycle and determining the drift to ensure that it is still within the limit of ±5%. No changes to the sampling system or EC analyzer calibration should be made until all of the post-test calibration checks have been recorded. The difference (% Drift) between the pre-test calibration and the post-test calibration should not exceed 5% for each pollutant.

EMISSIONS MEASUREMENTS

1. Testing should be conducted by personnel trained in the use of the specific EC analyzer utilized for the testing. Samples of pollutant concentrations should be taken from sample ports in the stack or using a "Shepard's hook" from a location in the stack such that a representative concentration is measured and bias (e.g., air leakage at weep holes) is prevented. A single sampling location near the center of the duct may be selected.

2. Prior to sample collection; ensure that the pre-test calibration has been performed. Zero the EC analyzer with fresh air, free from ambient CO and NO_X or other combustion gases. Each test for an emission unit should consist of at least three 10-minute measurement cycles. Position the probe at the sampling point and begin the measurement cycle at the same flow rate used during the calibration check. Measurements should not be recorded and averaged until the measurement system response time has passed. The EC analyzer should be "refreshed," the analyzer drift should be determined, and the moisture collection system emptied after each sampling cycle. Use the measurement data to calculate the mean effluent concentration. The Data recorder should record a reading at least every 60 seconds. Record the average gas sample concentration for each pollutant from the cycle on a form similar to the one provided.

3. Conduct the post-test calibration check after testing of each emission unit. If the sampling system is disassembled or if the EC analyzer calibration is adjusted, the EC analyzer should be recalibrated before conducting the next emission unit test.

4. The emissions testing should produce at least three sets of concentration data for each pollutant of concern. Results from each test represent a "quasi steady-state" measurement of pollutant concentration and the measured pollutant concentrations should be calculated as the mean gas concentration using the emissions data collected during the three test runs. Data from additional tests may be included in the calculation so long as other operational parameters remain relatively unchanged. To maintain consistency, the run length should be the same for all runs and all units.

5. The measured pollutant concentrations should then be corrected to give actual values using the pre-test calibration and post-test calibration results. The following equation should be used.

$$C_{ACTUAL} := \left(\boxed{C_{MEAS}} - C_{CZ}\right) \cdot \frac{\left(C_{CAL} - C_{CZ}\right)}{\left(C_{CM} - C_{CZ}\right)}$$

Where:

C_{ACTUAL} = actual pollutant concentration, ppmdv

C_{MEAS} = measured pollutant concentration, ppmdv

C_{CAL} = concentration of the calibration gas, ppmv

C_{CZ} = average of pre-test and post-test calibration zero checks, ppmdv

C_{CM} = average of pre-test and post-test measured concentrations of the calibration gas measurement checks, ppmdv

<u>Operational Parameter Measurements</u>:

1. During the emissions testing of the emission unit, the following operational parameters should be measured or determined:

    a. % Firing Rate
    b. Fuel BTU content
    c. Fuel Consumption

2. Sampling of the fuel, that is representative of the fuel combusted in the emission unit, should be performed. The fuel sampling should be conducted within a 24 hour period of the testing. The sample should be taken from the inlet gas line, downstream from any inlet separator, using a manifold to remove entrained liquids from the sample and probe to collect the sample from the center of the gas line.

3. The stack velocity or flow shall be measured or determined using one of the following methods:

    a. EPA Reference Method 19
    b. A method as approved by the Department, such as Method 2

<u>Calculations and Requirements for a Valid Test Run:</u>

<u>Oxygen Based F Factor, Dry Basis</u>

Use Method 19 equation 19-1.

$E = C_d F_d * (20.9/(20.9 - \%O_2 dry))$

Fd Calculation:

Use Method 19 Equation 19-13.

$$F_d = \frac{K(K_{hd}\%H + K_c\%C + K_s\%S + K_n\%N - K_o\%O)}{GCV} \qquad \text{Eq. 19-13}$$

Calibration Error:

Calibration Error = (Analyzer Response – Calibration Gas Concentration) / (Calibration Gas Concentration) * 100%. This value must be < 5% for a valid run.

% Interference

% Interference = Analyzer Response/Calibration Gas Concentration * 100%. This value must be <5% for a valid run.

% Drift

% Drift = (Post Test Analyzer Response – Pre-Test Analyzer Response)/(Pre Test Analyzer Response) * 100%. This value must be less than 5% for a valid test run.

Training:

Any persons performing the portable analyzer testing should be trained in the use of that portable analyzer and the associated concepts and principles of the emissions measurements and associated calculations.

Reporting

1. Use the following form when reporting results. This form is available electronically in Excel format and is available upon request, and is required to be reported on a quarterly basis.

2. Testing results that show emissions factors which are 10% or more higher than established during the last source test for the emitting unit, shall be reported within 2 weeks of the test. Such results will trigger the need for a full source test.

Calumet Portable Analyzer Emission Check
Monthly Monitoring Report

Tester Name				Ambient Temperature (°F)	
Tester Signature				Barometric Pressure (" Hg)	
Tester Title and Affiliation:				Date	

Emitting Unit Name as indicated in MAQP					
Fuel Factor (Fd) (dscf/MMBtu, as determined via Method 19 ultimate analysis on fuel burned on the testing date)					
Time Start					
Time Stop					
Check Zero NOx					
Check Zero CO					
Check Zero O2					
Check Span NOx (ppm)					
Check Span CO (ppm)					
Check Span O2 (ppm)					
Measured NOx (ppm)					
Measured CO (ppm)					
% O2					
Flue Gas Temp. (°F)					
Moisture (%)					
Check Zero NOx					
Check Zero CO					
Check Zero O2					
Check Span NOx (ppm)					
Check Span CO (ppm)					
Check Span O2 (ppm)					
NOx Calibration Error (%)					
NOx Interference (%)					
NOx Drift (%)					
CO Calibration Error (%)					
CO Interference (%)					
CO Drift (%)					
average % firing rate					
Maximum Rated Design Capacity (MMBtu/hr)					
Estimated lb/MMBtu emissions rate:					

notes: See Appendix 2 of the MAQP for equations, testing requirements, QA/QC requirements, and etc.

Montana Air Quality Permit (MAQP) Analysis
Calumet Montana Refining, LLC
MAQP #2161-30

I. Introduction/Process Description

Calumet Montana Refining, LLC (Calumet) operates a petroleum refinery located at the NE ¼ of Section 1, Township 20 North, Range 3 East, in Cascade County, Montana. The refinery is located along the Missouri River in Great Falls, Montana.

A. Permitted Equipment

The major permitted equipment at Calumet includes:

#1 Crude Unit
- Crude Heater H-0101 (30 million British thermal units per hour (MMBtu/hr))
- Vacuum Heater H-0102 (7 MMBtu/hr)

#2 Crude Unit
- Crude Heater H-2101 (71 MMBtu/hr)
- Vacuum Heater H-2102 (27 MMBtu/hr)

Catalytic Poly Unit

Fluidized Catalytic Cracking Unit (FCCU)
- FCCU Preheater
- FCCU Regenerator

Mild Hydrocracker Unit (MHC)
- Combined Feed Heater H-4101 (54 MMBtu/hr)
- Fractionator Feed Heater H-4102 (38 MMBtu/hr)

Catalytic Reformer Unit
- Reformer Heater
- Naphtha Heater
- Kerosene Heater
- Naphtha Hydrodesulfurization (HDS) Unit
- Kerosene HDS Unit

Alkylation Unit
- Deisobutanizer reboiler

Hydrogen Plants
- Hydrogen Plant Reformer #1
- Hydrogen Plant Reformer #2
- Hydrogen Plant Reformer #3 (Reformer H-31A & H-31B, each rated at 67 MMBtu/hr)

Hydrotreater Unit (HTU) Unit

Sodium Hydrosulfide (NaHS) Unit

Polymer-Modified Asphalt (PMA) Unit

- WT-1901 – wetting tank
- RT-1901 – reactor tank

Product Loading

- Truck Loading with Vapor Combustion Unit (VCU)
- Railcar Loading with VCU
- Railcar Loading (diesel and asphalt)

Utilities

- Boilers #1 & #2 with maximum rated capacity of 25 MMBtu/hr each
- Boiler #3 with maximum capacity of 60.5 MMBtu/hr
- Boiler #4 - Natural Gas Fired Only Temporary Boiler: maximum rated capacity of 89,873 scfh natural gas
- Wastewater
  - Surge Tank T-143, 18,000 bbl external floating roof
  - Surge Tank T-145, 37,000 bbl external floating roof
  - Aeration Tank TK-146
  - Slop Oil Tank 144, 600 bbl
  - Slop Oil Tank 144B, 300 bbl
  - Slop Oil Tank 186, 600 bbl each
  - API Separator
  - DAF Unit (Existing and New DAF unit in series)
  - Drains
- Cooling Towers

Storage Tanks, including:

- Heated Heavy Oil: #55, #56, #110, #112, #130, #132, #133, #135, #137, #139 #140
- #145B and #122, Wastewater surge tank (installed in 2006)
- Light Oil: #52, #54, #58, #100, #101, #122, #123, #125, #126
- Crude Oil: #201, #202, #203
- Heavy Oil: #36, #47, #48, #49, #63
- Misc: Naphtha Tanks #57, #124 and #127; Heavy Oil Tanks #44, #45, #11; #2 Diesel Tank #116; Raw Diesel Tank #128; NaHS Product, Caustic Tanks #35, #9, #115; Ethanol Tank #175, MHC Feed Tank #125
- Gasoline Tank #126
- Reformate Tank #127
- NaHS Tank #100, #101

- Firewater Tank #24
- Wastewater Tanks #143, #144B, #186
- Ammonia Tank #160

Flare System

- Primary Flare #1 – equipped with a caustic scrubber
- Secondary Flare #2 – back up to Flare #1

B. Source Description

Petroleum refining has been conducted at this site since the early 1920's. Calumet converts crude oil into a variety of petroleum products, including gasoline, diesel fuel, jet fuel, naphtha, asphalt, and NaHS.

C. Permit History

On December 2, 1985, the Montana Department of Health and Environmental Sciences and Montana Refining Company (MRC) signed a stipulation requiring MRC to obtain an air quality permit, and stipulated that a permit emission limitation of 4,700 tons per year (TPY) carbon monoxide (CO) would constitute compliance with ambient CO standards. MRC submitted this permit application with the intentions of permitting its existing refining operations, including all equipment not already permitted.

On October 20, 1985, MRC was granted a general permit for their petroleum refinery and major refinery equipment located in Great Falls, Cascade County, Montana. The application was given **MAQP #2161**.

The first alteration to their original permit was given **MAQP #2161-A** and was issued on May 31, 1989. This alteration involved the addition of a deisobutanizer reboiler.

The second alteration was given **MAQP #2161-A1** and was issued on March 12, 1990. This project involved the installation of one 30,000-barrel gasoline storage tank and one 40,000-barrel crude oil storage tank at the present facility. Both tanks were installed with external floating roof control.

The third alteration was given **MAQP #2161-A3** and was issued on December 18, 1990. This alteration consisted of the installation of a Hydrofluoric (HF) Acid Alkylation Unit, internal floating roofs at existing storage tanks, which had fixed roofs, and a safety flare.

The fourth alteration was given **MAQP #2161-04** and was issued on June 16, 1992. This alteration consisted of the installation of a NaHS unit at the existing Great Falls Refinery.

The NaHS unit receives refinery fuel gas (540,000 standard cubic foot per day (scf/day) maximum rated capacity) containing hydrogen sulfide (H_2S) and reacts with a sodium hydroxide caustic solution to remove virtually 100% of the H_2S by converting it to NaHS, a saleable product.

The resultant sweet fuel gas is burned, as before, in other process heaters. However, since the fuel gas contains virtually no H_2S, sulfur dioxide (SO_2) emissions from the process heaters, assuming no other changes, were decreased by nearly 60%. There was no decrease in permitted SO_2 emissions from this permit because the refinery wanted to retain the existing permitted SO_2 emission limitations so it could charge less expensive, higher sulfur crude oil.

In the basic process, off-gases from product desulfurizing processes (fuel gases) are contacted with a caustic solution in a gas contractor. The resultant reaction solution is continually circulated until the caustic solution is essentially used up; NaHS product is then sent to storage. Make-up caustic is added to the process as required. The process requires a gas contractor, process heat exchanger, circulation pump, storage tanks for fresh caustic and NaHS product, 12 pipeline valves, 4 open-ended valves, 21 flanges, and other process control equipment.

The only process emissions are fugitive Volatile Organic Compounds (VOC) from equipment (valves and flanges) in fuel gas stream service. To estimate unit VOC emissions, emission factors developed by the Environmental Protection Agency (EPA) for equipment in gas vapor service with measured emissions from 0 to 1,000 parts per million (ppm) are used. With an aggressive monitoring and maintenance program, fugitive VOC emissions from valves and flanges are within this 0 to 1,000-ppm range. Total annual fugitive VOC emissions from the NaHS units are estimated to be 20 pounds per year.

The tank that is to be used to store NaHS product was in jet fuel service. When taken out of jet fuel service, this tank (#35) is no longer a source of VOC emissions; the reduction in VOC emissions will be 2,270 pounds per year (PPY). Considering the 2,270-PPY decrease due to tank #35 service change, the refinery realized a net decrease in annual VOC emissions of 2,250 PPY or 1.1 TPY.

The fifth alteration was given **MAQP #2161-05** and was issued on October 15, 1992. This permit alteration was for the construction and operation of two 20,000-barrel capacity aboveground storage tanks at its Great Falls Refinery. The new tanks contain heavy naphtha (#127) and raw diesel (#128).

Each tank was constructed of metal sections welded together that rest on a concrete ring wall foundation. External floating roofs with dual seals are installed on each tank for VOC control.

On April 6, 1993, MRC was granted **MAQP # 2161-06** to construct and operate a HDS unit and hydrogen plant. This sixth alteration was required to go through New Source Review (NSR) - Prevention of Significant Deterioration (PSD) review for Oxides of Nitrogen (NO_X) and was deemed complete on February 22, 1993. The HDS project was designed to process 5,000 barrels per day (BPD) of diesel/gas oil and to reduce the sulfur content to 0.05 weight percent. The reduction of sulfur in diesel fuel and gasoline were mandated by the 1990 Clean Air Act Amendments and were accomplished by October 1993, and 1995, respectively. The desulfurizer unit operated by MRC was limited in size and throughput capacity to approximately 1,400 barrels per day.

The HDS project consisted of an HDS process unit and heater, hydrogen plant with reformer heater, and the removal of storage tanks #40 through #43. Tanks #40 and #41, which processed gas oil, were discontinued. Tanks #42 and #43 that process raw diesel were also discontinued. Tanks #44 and #111 were changed to gas oil use and Tank #45 which serviced JP-4 was changed to gas oil use.

On July 28, 1993, **MAQP #2161-07**, a modification to MRC's MAQP #2161-06, was issued to change the emission control requirements of the Section titled "Pressure Vessels."

In a system where the valves relieve to atmosphere, rupture discs can prevent emissions in the event of relief valve leakage. In HF systems, they can provide some protection from acid corrosion on the relief valve and acid salt formation. Except where HF acid is present, rupture discs do not provide any additional protection nor do they prevent any release of air contaminates in a closed relief system.

In heavy liquid service, rupture discs can be safety hazards by partial failure or leaking and changing, over time, the differential pressure required providing vessel protection. Therefore, only pressure vessels in HF Acid service shall be equipped with rupture discs upstream of the relief valves and all except storage tanks shall be vented to the flare system.

Also, the allowable particulate emission limitation for MRC's FCCU was corrected to reflect the maximum allowable emissions based on the process weight rule (Administrative Rules of Montana (ARM) 17.8.310). The maximum allowable emissions were calculated to be 234.53 TPY using a catalyst circulation rate of 125 tons per hour (TPH).

MRC requested a permit modification, **MAQP #2161-08**, to remove the alkylation unit and tanks #127 and #128 from New Source Performance Standards (NSPS) status because they were erroneously classified as affected facilities under NSPS when originally permitted. This request for modification was submitted on August 11, 1993, and issued on January 6, 1994.

When MRC applied for the preconstruction permit to build the HF Alkylation Unit in 1990, it was presumed, since this unit was new to MRC, it automatically fell under NSPS as new construction. Subsequently, it has been determined that if a source is moved as a unit from a location where operation occurred (Garden City, Kansas) to another location, it must meet the definition of reconstruction or modification in order to trigger NSPS applicability.

The alkylation plant was originally constructed in Garden City, Kansas during 1959 - 1960 and moved, in its entirety, to Great Falls and installed. Since the unit was originally constructed before the NSPS-affected date of January 5, 1981, it does not meet the criteria for construction date of a new source under 40 Code of Federal Regulations (CFR), Subpart GGG or Subpart QQQ.

The project did not meet the criteria under reconstruction because no capital equipment was replaced when the unit was relocated. The replacement work performed, as the unit was moved, amounted to pump seals, valve packing, bearings, small amounts of corroded piping, and some heat exchanger tubes and bundles, all of which are done routinely as maintenance. The VOC emitters, such as valve packing and pump seals, were upgraded to meet Best Available Control Technology (BACT).

Along the same line, tanks #127 and #128 were originally constructed at Cody, Wyoming in 1960 and relocated to Great Falls in 1993. The only change was the modification of the roof seals to double seals to meet BACT. This cost of modification was a total of $15,000 for both tanks as compared to more than $500,000 if two new tanks were to be built.

Also, on October 28, 1993, MRC submitted a permit application to alter the existing permit. This modification and alteration of the existing permits were assigned MAQP #2161-08. MRC proposed to construct and operate a 3,500 barrel-per-day asphalt polymerization unit. The unit enabled MRC to produce a polymerized asphalt product that would meet future federal specifications for road asphalt, as well as supply polymerized asphalt to customers that wished to use the product.

The proposed unit consisted of two circuits: the asphalt circuit and the hot oil circuit. In the asphalt circuit, polymerization occurs in a 1,000-barrel steel, vented mix tank. Product blending and storage occurs in 3 steel, vented 1,000 barrel tanks identified as A, B, and C. Existing Tanks #55 and #56 (3,000 barrels each) remained in asphalt service and are used for storage. In addition to the above equipment, the asphalt circuit also consisted of 4 pumps and approximately 47 standard valves. All the above equipment became part of the asphalt service and, except for Tanks #55 and #56, was new.

To maintain the asphalt at the optimum temperature in the storage and blending tanks, a hot circuit was utilized. Hot oil (heavy fuel oil) was heated in an existing permitted process heater (Tank #56 heater) and circulated through coils in the process tankage. No change in the method of operation of the heater was anticipated. A steel, vented hot-oil storage/supply tank was utilized to maintain the required amount of hot oil in the unit. In addition to the process heater and storage/supply tank, the hot-oil circuit consisted of one pump and approximately 56 standard valves. The above equipment was used in hot-oil service and, except for the heater, was new.

An annual emissions increase of 7.3 TPY of VOC was expected due to operation of the unit. It was anticipated that the unit would be operated only 6 months of the year. The VOC emissions resulted from the vented hot-oil tank and the valves and pump in hot-oil service.

MAQP #2161-09 was issued on September 6, 1994, and included a change in the method of heating three previously permitted polymer modified asphalt tanks. As previously permitted, these tanks were heated utilizing circulating hot oil. The tanks were heated individually using natural gas fired fire-tube heaters. The use of natural gas eliminated the hot-oil circuit, including the hot-oil storage tank, entirely.

Since the initial permit application for the modified asphalt unit, several small design changes occurred involving the addition of a new 800-gallon wetting tank for asphalt service. An output line from existing Tank #69 (Tall Oil) was also added. This output line added approximately 12 new valves and one new pump, all in Tall Oil service, to the unit. All other valves and pumps were designated to be in asphalt service.

All VOC emissions from equipment and tanks in asphalt service were assumed to be negligible, since asphalt has negligible vapor pressure at the working temperatures seen in the unit.

MAQP #2161-10, for the installation of an additional boiler (Boiler #3) to provide steam for the facility, was never issued as a final permit. On May 28, 1997, the Department of Environmental Quality – Air Resources Management Bureau (Department) received a letter requesting the withdrawal of the permit application and the withdrawal was granted to MRC. A summary of this permitting action is included in the analysis for MAQP #2161-11.

MAQP #2161-11 was issued on January 23, 1998, for the installation of a vapor collection system and enclosed flare for the reduction of Hazardous Air Pollutants (HAP) resulting from the loading of gasoline. This was done in order to comply with the gasoline loading rack provisions of 40 CFR 63, Subpart CC - National Emission Standards (NES) for Petroleum Refineries. A VCU was added to the truck loading rack. The gasoline vapors are collected from the trucks during loading then routed to an enclosed flare where combustion occurs. The result of this project was an overall reduction in the amount of VOC and HAPs emitted, and a slight increase in CO and NO_x emissions.

Because MRC's bulk gasoline and distillate truck loading rack VCU was defined as an incinerator under Montana Code Annotated (MCA) 75-2-215, a determination that the emissions from the VCU would constitute a negligible risk to public health was required prior to the issuance of a permit to the facility. MRC and the Department identified the following HAPs from the flare that was used in the health risk assessment. These constituents are typical components of MRC's gasoline.

1. Benzene
2. Toluene
3. Ethyl Benzene
4. Xylenes
5. Hexane
6. 2,2,4-Trimethlypentane
7. Cumene
8. Naphthalene
9. 1,3-Butadiene

The reference concentrations for Benzene, Toluene, Ethyl Benzene, and Hexane were obtained from EPA's IRIS database. The risk information for the remaining HAPs was contained in the January 1992 CAPCOA Risk Assessment Guidelines. The ISCT3 modeling performed by MRC for HAPs identified above demonstrated compliance with the negligible risk requirement.

MRC requested, via a letter dated August 13, 1997, changes to administratively and technically correct MAQP #2161-09. These changes were necessary as a result of the withdrawal of MAQP #2161-10. The changes included correctly stating opacity limits relating to asphalt storage tanks, removing references to procedural rules, changing monitoring requirements for the HTU Sour Water Stripper (SWS) and changing performance specifications for the continuous H_2S monitoring system.

The Department issued Draft Modification #2161-11 on November 6, 1997, to address the permit changes that were requested by MRC. The Department received comments on November 13, 1997, from MRC and later met on November 17, 1997, to discuss the draft modification. Because MRC had applied for a permit alteration on October 21, 1997, for the loading rack VCU, the draft modification was addressed in the permit alteration request.

The Department issued Preliminary Determination #2161-11 on November 26, 1997. The Department received comments from MRC on December 4, 1997, December 10, 1997, December 15, 1997, and December 30, 1997. The Department responded to these comments via faxes on December 8, 1997, December 11, 1997, and December 16, 1997. On December 23, 1997, the Department was prepared to issue a Department Decision, but MRC requested, via telephone, that the decision not be issued until after the holidays. The decision was required to be issued by January 8, 1998, to meet the mandated time frames for issuing a Department Decision.

MAQP #2161-12 was not issued. MRC applied for a modification on February 18, 1998, and this action was given #2161-12. On February 27, 1998, the Department notified MRC that the permitting actions requested would require an alteration and that a complete preconstruction permit application would be required.

MAQP #2161-13 placed enforceable emission limits on the facility, both plant-wide and the #1 and #2 boilers. The emission limits showed, through the use of EPA-approved models, to protect the National Ambient Air Quality Standards (NAAQS) for SO_2.

The continuous gas flowmeters installed on the vacuum heater and the crude heater were placed in the permit. Also, the #1 and #2 boiler limits were updated to allow MRC more flexibility in their operations. The limits were originally placed on the boilers to keep MRC below the PSD permitting threshold. The new limits maintained MRC's status below the PSD permitting threshold.

The monitoring location was identified in Attachment 1 Ambient Air Monitoring Plan. The current location was determined to be inappropriate after reviewing the modeling analysis, and the new location was approximately 1.2 km from its present location. The monitoring location was chosen based on the modeling analysis that was submitted and is required to provide monitored confirmation of compliance with the Montana SO_2 Standards.

The method numbers for examination of water and wastewater were updated. The conditions in MAQP #2161-13 were incorporated into the Operating Permit and the compliance demonstration methodology for those conditions was evaluated at the time of the Operating Permit's issuance. MAQP #2161-13 replaced MAQP #2161-11.

On August 4, 2001, the Department issued **MAQP #2161-14** for the installation and operation of five 1600-kilowatt (kW) diesel-powered, temporary generators. These generators were necessary because of the current high cost of electricity. The generators would only operate for the length of time necessary for MRC to acquire a permanent, more economical, supply of power. Further, the generators are limited to a maximum operating period of 2 years.

Because these generators would only be used when commercial power is cost prohibitive, the amount of emissions expected during actual operation is minor. In addition, because the permit limits the operation of these generators to a time period of less than 2-years, the installation and operation qualifies as a "temporary source" under the PSD permitting program. Therefore, the proposed project does not require compliance with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, the Department requires compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 will be ensured. Finally, MRC is responsible for complying with all applicable ambient air quality standards. MAQP #2161-14 replaced MAQP #2161-13.

On August 17, 2002, the Department issued **MAQP #2161-15** to eliminate the summer boiler SO_2 emission limits (both the plant-wide and 24-hour average) and redefine the winter limits as year-round limits. The seasonal limits were originally placed in the permit to allow MRC more flexibility when operating the boilers. Both the winter and summer scenarios were supported by ambient air quality modeling performed prior to MAQP #2161-13 being issued. The winter limit being redefined as a year-round limit does not represent an increase in SO_2 emissions from the boilers or any other emitting point. In addition, the Department removed requirements to determine and report NO_X emissions both from the crude heater (due to the old SWS) and refinery wide, as these sources are not subject to NO_X emissions limitations. The requirements appeared to have been inadvertently applied through an administrative error. MRC already provides refinery-wide NO_X emissions as part of its annual Emission Inventory submission to the Department. MAQP #2161-15 replaced MAQP #2161-14.

On March 19, 2003, the Department issued **MAQP #2161-16** to include certain limits and standards associated with the Consent Decree lodged on December 20, 2001. In addition, the permit was updated with new rule references under ARM 17.8, Subchapter 7. MAQP #2161-16 replaced MAQP #2161-15.

The Department received a request to modify MAQP #2161-16 on July 10, 2003, to change the emission testing schedule for the gasoline truck loading vapor combustion unit to be consistent with MRC's current operating permit. MRC also requested the Department clarify the 7,000-BPD limit of crude charge (referenced in MRC's Title V Operating Permit) is no longer valid. Should MRC's normal processing exceed 7,000-BPD, MRC would be required to comply with ARM 17.8.324, as applicable. In a letter received by the Department on September 30, 2003, MRC also requested to add three new asphalt tanks with associated natural gas heaters. The emissions from the three tanks met the requirements of the de minimis rule and were added to the permit. The permit action updated the permit to reflect the changes. **MAQP #2161-17** replaced MAQP #2161-16.

On May 14, 2004, the Department received a letter from MRC requesting changes to MAQP #2161-17. The proposed change includes adding the ability to burn sweet gas in heaters at the HF Alkylation Unit, and at Tanks 102, 135, 137, 138, and 139. The sweet gas will have a H_2S limit equivalent to the 40 CFR Part 60, Standards of Performance for NSPS, Subpart J limit of 0.10 grains per dry standard cubic foot (gr/dscf) H_2S. The continuous refinery fuel gas monitoring system for H_2S installed on the fuel gas system that supplies the heaters would be used to determine compliance with the limit. Since the emissions from switching the fuel to sweet gas were less than the de minimis threshold, the Department added the fuel switch. The permit action updated the permit to reflect these changes. **MAQP #2161-18** replaced MAQP #2161-17.

On May 17, 2007, the Department received an application from MRC for the installation of a railcar product loading rack controlled by a John Zink VCU. On June 19, 2007, MRC clarified that gasoline and naphtha were the only products that will go through the new railcar loading rack, and that other liquid products already loaded into railcars (diesel, jet fuel, etc.) would not be affected.

The gasoline railcar loading rack is subject to 40 CFR 63, Subpart CC, which requires MRC to comply with specific bulk loading requirements in 40 CFR 63, Subpart R. Subpart R restricts the operation of the railcar loading system to less than 10 milligrams (mg) of VOC per liter of gasoline loaded and requires the operation of a continuous monitor downstream from the firebox. Furthermore, the gasoline and naphtha railcars are considered as 'gasoline cargo tanks' and are required to comply with the leak detection testing requirements. Lastly, 40 CFR 63, Subpart CC requires MRC to comply with 40 CFR 60, Subpart VV to minimize fugitive equipment leaks.

Other new applicable regulations were added, including 40 CFR 63, Subpart UUU, Subpart EEEE, and Subpart DDDDD. Consent Decree #CIV-01-1422LH requirements, entered March 5, 2002 (Consent Decree), were included, such as the new requirements to comply with 40 CFR 60, Subpart J limits for refinery fuel gas and SWSOH. Other changes completed in this permit action were: adding FCCU uncorrected CO emissions from 40 CFR 63, Subpart UUU, and SO_2 and NO_X emission limits resulting from the Consent Decree; and revising the permit to reflect the operation of a continuous H_2S fuel gas meter and requirement to comply with 40 CFR 60, Subpart J. **MAQP #2161-19** replaced MAQP #2161-18.

On October 15, 2007, the Department received letter from MRC requesting a correction to MAQP #2161-19, to remove the restrictions on the type of fuel used in specific asphalt tank heaters, which was added erroneously during the previous permitting action. In addition, the MAQP was updated to reflect the fact that requirements under 40 CFR 63, Subpart DDDDD are now "state-only" since the federal rule was vacated in Federal Court on July 30, 2007. **MAQP #2161-20** replaced MAQP #2161-19.

On June 9, 2008, the Department received a letter from MRC requesting an amendment to MAQP #2161-20, to modify the restrictions on Storage Tank #8. This request was a follow-up to a de minimis request received by the Department on April 21, 2008, where MRC proposed to change the operation of Storage Tank #8 from NaHS to naphtha. The Department reviewed this de minimis request and determined that MAQP #2161-20 must first be amended as described in the ARM 17.8.745(2) and ARM 17.8.764 before this change would be allowed. Although the potential emissions increase for this project is less than the de minimis threshold, the proposal would have violated a condition of MRC's current permit. Specifically, the MAQP states, "Storage tanks #8, #9, #50, #55, #56, #69 #102, #110, #112, #130, #132, #133, and #135 shall be used for asphalt, modified asphalt, or tall oil service (ARM 17.8.749)." This permit has been amended to allow the proposed change in operation of Storage Tank #8.

On July 2, 2008, the Department received another letter from MRC requesting an administrative amendment to MAQP #2161-20 to include certain conditions specified in the Administrative Order on Consent (AOC) that MRC entered into with the Department on May 13, 2008. The AOC requires MRC to install and operate a SO_2 and Oxygen (O_2) continuous emission monitor system (CEMS) on the stack for the #1 and #2 Boilers. This SO_2/O_2 CEMS is to be used as the primary analytical instrument to determine compliance with state and federal SO_2 requirements. The AOC requires MRC to request that these conditions be included in the MAQP as enforceable permit conditions.

In addition, MRC requested that the permit be amended to allow certain de minimis changes related to the Diesel/Gas Oil HDS heater and three PMA tank heaters. Specifically, MRC requested that refinery fuel gas, in addition to natural gas, be allowed to be burned in these heaters. The current permit requires that the Diesel/Gas Oil HDS heater and the three PMA tank heaters be fired only with natural gas. This requirement is based on BACT. For the Diesel/Gas Oil HDS heater, the BACT analysis requires that low sulfur fuel be used. Since the refinery fuel gas is also a low sulfur fuel meeting 40 CFR 60, Subpart J requirements of 160 ppm H_2S, the Department determined that the proposed change does not violate any applicable rule and therefore, can be allowed through an administrative amendment as specified in ARM 17.8.745(2) and ARM 17.8.764. For the three PMA tank heaters, however, the BACT analysis specifically requires that these heaters be fired with natural gas for control of NO_x emissions. Therefore, the Department determined that the proposed three PMA tank heaters de minimis changes are prohibited under ARM 17.8.745(1)(a)(i) since an applicable rule, specifically ARM 17.8.752 requiring that BACT be utilized, would be violated. Because BACT determinations cannot be changed under the amendment process, the Department requested that MRC submit an application for a permit modification that would include a revised BACT analysis in order to make the proposed change for the three PMA tank heaters.

In addition, the Department updated Attachment 1 to reflect the most current permit language and requirements for ambient monitoring. **MAQP #2161-21** replaced MAQP #2161-20.

On December 19, 2008, the Department received a request from MRC to amend MAQP #2161-21. MRC requested to change the wording for material stored in specified storage tanks to language representative of the requirements of 40 CFR 60, Subpart Kb in order to provide operational flexibility. Instead of referring to specific products (e.g., naphtha, gasoline, diesel, tall oil, etc.), the products would instead be referred to as light oils, medium oils, and heavy oils.

Under MRC's proposed language, light oils would be defined as a volatile organic liquid with a maximum true vapor pressure greater than or equal to 27.6 kilopascal (kPa), but less than 76.6 kPa and would include, but not be limited to, gasoline and naphtha. Medium oils would be defined as volatile organic liquids with a vapor pressure less than 27.6 kPa and greater than or equal to 5.2 kPa and would include, but not be limited to, ethanol. Heavy oils would be defined as volatile organic liquid with a maximum true vapor pressure less than 5.2 kPa and would include, but not be limited to diesel, kerosene, jet fuel, slurry oil, and asphalt.

In addition to making the requested change, the Department has clarified the permit language for the bulk loading rack VCU regarding the products that may be loaded in the event the VCU is inoperable and deleted all references to 40 CFR 63, Subpart DDDDD: NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters, as it was removed from the ARM in October 2008. The Department has also updated Attachment 1, Ambient Monitoring to reflect the most current permit language and requirements for ambient monitoring. **MAQP #2161-22** replaced MAQP #2161-21.

On July 9, 2009, the Department received a permit application from MRC to modify MAQP #2161-22. The application was deemed complete on July 24, 2009. MRC submitted a permit modification to allow the use of treated refinery fuel gas or natural gas in the tank heaters. Previously, the PMA tanks heaters were permitted to use natural gas only pursuant to a BACT analysis that was completed for MAQP #2161-09. This permit modification applied to three previously permitted asphalt tanks (Tanks #130, 132 and 133) and the associated PMA tank heaters. **MAQP #2161-23** replaced MAQP #2161-22.

On January 15, 2008, the Department received a request from MRC to install a second hydrogen plant that utilizes a process heater with a heat input of 80 million British thermal units per hour (MMBtu/hr). The Department approved this de minimis request on February 8, 2008. Pursuant to the Consent Decree (CD) and the approval of the de minimis request, MRC was required to conduct an initial performance test on the process heater with the results reported based upon the average of three, one hour testing periods. The CD also required MRC to submit an application to the Department and to propose a NO_x permit limit for the heater. MRC submitted a permit application on December 29, 2009 and the Department deemed this application incomplete on January 15, 2010. On July 12, 2010, MRC submitted additional information as requested by the Department. On September 2, 2010, during the comment period, MRC submitted information to support the guaranteed ultra-low NO_x burner emission limit of 0.033 lb/MMBtu based on the Higher Heating Value (HHV) of the fuel. This limit was based on the process heater of the hydrogen plant operating at full capacity (80 MMBtu/hr) with fuel gas consisting of 40.5 % natural gas and 59.4% Pressure Swing Adsorption (PSA) vent gas. This permit modification applied to NO_x limits on the Hydrogen Plant #2 process heater. **MAQP #2161-24** replaced MAQP #2161-23.

On July 6, 2011, MRC submitted a permit application and subsequent modeling demonstration to add a new boiler (Boiler #3) capable of firing refinery fuel gas, SWSOH, or natural gas at the petroleum refinery. The primary purpose of Boiler #3 is to supplement the two existing boilers (#1 and #2) that provide process steam to the refinery. The design burner heat input capacity for Boiler #3 varies, depending upon fuel characteristics, from 59.7 to 60.5 MMBtu/hr. The Department deemed the application incomplete on August 4, 2011, and MRC provided additional information in response to the Department's letter on September 26, 2011.

On October 25, 2011, the Department requested additional information with respect to MRC's plantwide applicability limit (PAL) and the SWSOH combustion properties. This information was received by the Department on November 15, 2011. Additionally, because MRC experienced significant downtime with the SO_2/O_2 CEMS required on the #1 and #2 Boiler stack, MRC submitted a request to allow the use of the H_2S fuel gas analyzer located near the fuel gas drum as backup to the SO_2/O_2 CEMS. MRC also requested this for Boiler #3.

Therefore in addition to adding the Boiler #3 to the refinery's operation, the permit action also added compliance, reporting and recordkeeping requirements for allowing the H_2S fuel analyzer to be used as a backup to the SO_2/O_2 CEMS. When the H_2S fuel analyzer is used, MRC would not be allowed to route the SWSOH to the boilers. **MAQP #2161-25** replaced MAQP #2161-24.

On October 24, 2012, the Department received a request for the transfer of ownership. According to the information submitted, the previous owner, Connacher Oil and Gas, sold its shares of MRC to Calumet Specialty Products Partners. With the transfer of ownership, Calumet Specialty Products Partners also requested a facility name change from MRC to Calumet Montana Refining, LLC. This was an administrative permit action to change the name. **MAQP #2161-26** replaced MAQP #2161-25.

On July 30, 2013, the Department received an application for modification to MAQP #2161-26. The permit action removed older storage tanks that were located close to the process unit area and in order to accommodate potential future expansion. As such, Calumet requested to remove nine (9) tanks and to add eight (8) new tanks as shown in the table below:

Current Tank ID	Current Service	Current Capacity (in barrels (bbl))	New Tank ID	Service	New Capacity (in bbl)
Tank #122	Unleaded Gasoline	11300	Tank #122	Unleaded Gasoline	20000
Tank #123	Unleaded Gasoline	11300	Tank #123	Unleaded Gasoline	20000
Tank #52	Premium Gasoline	3000	Tank #52	Premium Gasoline	11300
Tank #53	Premium Gasoline	3000	Removed from service		

Current Tank ID	Current Service	Current Capacity (in barrels (bbl))	New Tank ID	Service	New Capacity (in bbl)
Tank #46	Kero/Jet A	5140	Tank #49	Kero/Jet A	20000
Tank #47	Kero/Jet A	10500	Tank #47	Kero/Jet A	20000
Tank #48	Kero/Jet A	10500	Tank #48	Kero/Jet A	20000
Tank #50	Asphalt	55700	Tank #50	Asphalt	20000
Tank #102	Asphalt	10300	Tank #102	Asphalt	20000

All kerosene and asphalt tanks were equipped with fixed roofs, and all gasoline storage tanks are equipped with external floating roofs. In addition, tanks 50 and 102 are equipped with two burners (John Zink Burner), each rated at 2.3 MMBtu/hr to keep the asphalt from cooling down and/or hardening. **MAQP #2161-27** replaced MAQP #2161-26.

The Department issued a preliminary determination (PD) as **MAQP #2161-28** on March 18, 2014, final department decision (DD) on April 25, 2014, and final permit on May 13, 2014. However, the Department did not notify the public by advertisement in a newspaper of general circulation in the Great Falls area in accordance with ARM 17.8.826(2)(c) when it issued the PD for MAQP #2161-28. Therefore, the Department reissued its PD under **MAQP #2161-29** along with a public notice in the Great Falls Tribune to satisfy the requirements of ARM 17.8.826(2)(c). All project analyses and conclusions from MAQP #2161-28 for this project remained the same. MAQP #2161-29 contained any comments received on the PD for MAQP #2161-28 and corrections made to address them.

On October 3, 2013, the Department received a permit application requesting a major modification under the New Source Review-Prevention of Significant Deterioration (NSR-PSD) program. This permit application was assigned MAQP #2161-28. The project was deemed significant for greenhouses (GHG) and volatile organic compounds (VOCs), and the permit application was deemed complete on February 10, 2014.

With this permit action, Calumet proposed to increase the low sulfur fuels capacity at the refinery from approximately 10,000 bpsd throughput up to 30,000 bpsd while increasing yields of distillates, kerosene, diesel, and asphalt products.

The expansion project included the construction of four new processing units: a new crude unit that will process heavy sour crudes, a MHC for gas-oil conversion to higher value distillates, a new hydrogen plant (#3) to support the MHC, and a fuel gas treatment unit to handle the increased fuel gas production from the MHC.

The main emitting units included with the expansion project are as follows: Hydrogen Plant #3 (equipped with two heaters with a total combined firing rating of up to 134 million British thermal units per hour (MMBtu/hr)); Combined Feed Heater (up to 54 MMBtu/hr); Fractionation Feed Heater (up to 38 MMBtu/hr), Crude Heater (up to 71 MMBtu/hr), Vacuum Heater (up to 27 MMBtu/hr), and a new flare interconnected to the existing flare that will be equipped with a flare gas scrubber. With the expansion, Calumet also proposed to add a new rail car loading (diesel and asphalt) and unloading (crude oil and gas oil) area, and several new storage tanks in addition to re-purposing some existing storage tanks to accommodate the expansion project.

Additionally, the existing HTU that block operated in both diesel and gas-oil service was to become the kerosene HTU, and the existing kerosene HTU was to become a Naptha HTU. Lastly, Calumet requested a federally enforceable operational limit on Boiler #1 and Boiler #2.

D. Current Permit Action

On April 4, 2017 the Montana Department of Environmental Quality – Air Quality Bureau received an application from Calumet to modify the existing MAQP. Incompleteness responses and additional information were received, with final information completing the application on September 26, 2017. Due to various operational and design issues, compliance with certain limits associated with the expansion project permitted in MAQP #2161-29 were determined to be unachievable on a continuous and ongoing basis. These limitations were necessary to avoid the project being determined a major modification of a major stationary source and subject to the permitting requirements of ARM 17.8 Subchapter 8 for NO_x. As such, Calumet has proposed an alternative operating scenario and alternative limitations to maintain the project below relevant significant emissions rates.

Calumet proposes to install a new boiler, potentially on a temporary basis, has proposed an 'umbrella' limit on emissions of NO_x and CO on a rolling 12-month basis, and has proposed to install an ammonia combustor to remove and combust fuel bound nitrogen that otherwise would be present in refinery fuel gas.

The 'umbrella' limit would apply to combined emissions from multiple units. This approach provides Calumet operational flexibility regarding the emitting units included in the limit such that any combination of emissions from these units, provided the overall sum is less than the provided limits, satisfies the requirements to maintain the project as not triggering a major modification for NO_x or CO. Prior limitations related to PSD avoidance on Boilers #1 and #2 have been removed.

Calumet has determined a need to reduce fuel-bound nitrogen in fuel gas in order to meet NO_x limitations on various units with a comfortable compliance margin. Further, Calumet has found mechanical issues with Boiler #3 which has further resulted in potential for excess NO_X emissions specific to Boiler #3. Bringing a low NO_X boiler on-site will allow Calumet to produce steam required for some level of operations while ongoing efforts to reduce plant wide NO_X emissions are undertaken. The low NO_X boiler will provide for reduced emissions of NO_X per pound of steam produced compared to the NO_X performance capabilities of Boilers #1 and #2.

Boiler #3, the new boiler, and the ammonia combustor have been determined technically and economically related to the expansion project. As such, the expansion project is required to be permitted from the perspective of adding these units as new units. The purpose of this permitting action is to establish limits which maintain the net emissions increases from this project to less than the significant emissions rates of ARM 17.8.801(28) for NO_x and CO, or less than the amount of other emissions previously reviewed for the expansion project. All pollutants are reviewed and the expansion project is essentially re-permitted as if the project had not been permitted before. Any request in the future to relax these limits or modify or replace associated units would require a reassessment of the project netting analysis. The allowable operating capacity of the associated refining unit heaters is reduced in the current operational scenario, and future projects at the refinery to reduce emissions will be necessary to gain full use of the increased refining capacity capable of being accomplished with the associated equipment installed, if avoidance of PSD permitting is continued to be desired.

During PSD Netting review, Calumet identified that Tank #50 and #102, originally to be equipped with tank heaters, will no longer be equipped with tank heaters. Preconstruction approval of these heaters has been removed. **MAQP #2161-30** replaces MAQP #2161-29.

E. Response to Public Comment

This section will summarize any public comments received in writing during the public comment period and the Department's response to those public comments.

Entity	**Permit Reference**	**Comment**	**Department Response**
Calumet Montana Refining, LLC via Elisa Rockholt	Sections II.D.3.a & II.D.4.a	Calumet requests the two conditions be revised to accommodate the various methods of emissions testing. This change would revise the last sentence of the condition to read: "…Units equipped with NOx CEMS shall conduct a RATA as required." And add an additional condition as follows: "Emission factors in lb/MMBtu will be determined from the most recent emissions testing; portable analyzer test, source test or performance test, as applicable."	The comment has been incorporated as requested.
Calumet Montana Refining, LLC via Elisa Rockholt	Sections II.D.3 & II.D.4	Calumet requests that a condition be added stating that portable analyzer testing is not required in months in which source testing or performance testing are performed.	The comment has been incorporated as requested.

Calumet Montana Refining, LLC via Elisa Rockholt	Sections II.E.3.d, II.E.5.b and II.E.9.a	In cases where annual performance tests were previously required (II.E.3.d, II.E.5.b and II.E.9.a) but now annual source testing will be occurring and performance tests are not required by Consent Decree or compliance with Subpart Ja, Calumet requests the conditions for annual performance tests be removed. In the case of Boiler #3, in order to maintain compliance with the NOx emissions Subpart Ja does require biennial performance tests in conjunction with an O_2 CEMS. In this case a source test would be performed in alternate years.	The comment is addressing duplicative testing conditions in the permit. The comments have been incorporated as requested
Calumet Montana Refining, LLC via Elisa Rockholt	Section II.C.24	The Sour Water Stripper Ammonia Combustor is subject to Ja and must demonstrate compliance with SOx emissions by continuously monitoring either the H_2S in the fuel gas stream or the SO_2 in the stack emissions. Condition II.C.24 would require the Calumet to monitor the H_2S in the fuel gas stream. Due to safety concerns that need to be evaluated further, Calumet prefers to maintain the option to monitor either the H_2S in the fuel gas stream or the SO_2 in the stack emissions as prescribed by 40 CFR 60 Subpart Ja.	The comment has been incorporated as requested. The underlying condition and compliance demonstration has been updated to provide flexibility in choosing an H_2S limit or SO_2 limit based on Calumet's chosen compliance demonstration methodology
Calumet Montana Refining, LLC via Elisa Rockholt	II.A.20 and conditions following	There were a few places within the permit where minor formatting adjustments would make the reading of the permit easier. For example, conditions pertaining to the Sour Water Stripper Ammonia Combustor (Section II.A.20 on page 20) are numbered in sequence (20, 21, 22, …) as opposed to (20, a. – f).	The permit conditions have been renumbered / reformatted.

F. Additional Information

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

II. Applicable Rules and Regulations

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

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

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

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

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

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

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

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

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

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

1. ARM 17.8.204 Ambient Air Monitoring
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
7. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
8. ARM 17.8.221 Ambient Air Quality Standard for Visibility
9. ARM 17.8.222 Ambient Air Quality Standard for Lead
10. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

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

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

1. ARM 17.8.304 Visible Air Contaminants. (1) This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed on or before November 23, 1968, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes. (2) This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

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

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

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

5. ARM 17.8.322 Sulfur Oxide Emissions – Sulfur in Fuel. (5) Commencing July 1, 1971, no person shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions. Calumet is a small refinery (under 10,000 BPD crude oil charge) and is, therefore, exempt from this rule, provided that they meet the other provisions of this rule.

6. ARM 17.8.324 Hydrocarbon Emissions – Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule. Calumet is subject to this rule when Calumet's normal processing exceeds 7,000 bbl/day of crude charge.

7. ARM 17.8.340 Standard of Performance for New Stationary Sources. This rule incorporates, by reference, 40 CFR Part 60, NSPS. The owner or operator of any stationary source or modification, as defined and applied in 40 CFR Part 60, shall comply with the standards and provisions of 40 CFR Part 60, NSPS. The applicable NSPS Subparts include, but are not limited to:

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

   b. Subpart Dc – Standards of Performance for Small Industrial-Commercial Institutional Steam Generating Units for which construction, modification, or reconstruction is commenced after June 9, 1989. This Subpart would apply to the Boiler #3.

      Boiler #4 is expected to be a "temporary boiler" as defined for this subpart. Boiler #4 would become subject to this standard if any of the following conditions are determined:

      - Boiler #4 remained on location for more than 180 days
      - Boiler #4 is attached to a foundation
      - Boiler #4 is moved from one location to another in an attempt to circumvent the 180 day residence time.

   c. Subpart J – Standards of Performance for Petroleum Refineries. This Subpart applies to facilities that are constructed or modified after June 11, 1973; therefore, new and modified fuel gas combustion devices will be subject to the provisions of Subpart J. In addition, the following shall apply, as described per the Consent Decree:

      - FCCU regenerator: for CO and for SO_2, and
      - Heaters, boilers and flare (constructed or modified on or before May 14/2007).

   d. Subpart Ja – Standards of Performance for Petroleum Refineries for which Construction, Reconstruction or Modification Commenced After May 14, 2007. This Subpart applies to fuel combustion units (heaters and flares) that are constructed or modified after May 14, 2007.

   e. Subpart Kb – Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction or Modification Commenced After July 23, 1984.

Note: The five tanks used in the PMA unit, listed below, are exempt from the provisions of Subpart Kb because the true vapor pressure (TVP) of the Volatile Organic Liquid (VOL) stored is less than 3.5 kilopascals (Kpa) (0.5076 pounds per square inch atmosphere (psia)).

PMA Unit

Tank	Capacity	TVP (psia)
WT-1901 wetting tank	800 gal	negligible
RT-1901 reactor tank	715 bbl	negligible
asphalt storage (3)	1,000 bbl	negligible

f. Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture – shall apply to all asphalt storage tanks that process and store only non-roofing asphalts, and was constructed or modified since May 26, 1981.

g. Subpart VV – Standards of Performance for Equipment Leaks of Volatile Organic Compounds (VOC) in the Synthetic Organic Chemicals Manufacturing Industry, shall apply to this refinery as required by 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC.

h. Subpart VVa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.

i. Subpart GGG – Equipment Leaks of VOC in Petroleum Refineries shall not apply to the following units:

Equipment	Year of Mfg.	Year of Install.
HF Alkylation Unit	1960	1990

j. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006. Unless exempt, this standard applies to compressors, valves, pumps, pressure relief devices, sampling connection system, open-ended valves and lines, flanges, and connectors that are part of the #2 Crude Unit -expansion project.

k. Subpart QQQ – VOC Emissions from Petroleum Refinery Wastewater Systems does not apply to the following units:

Equipment	Year of Mfg.	Year of Install.
HF Alkylation Unit	1960	1990

l. All other applicable subparts and referenced test methods.

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

   a. Subpart A – General Provisions applies to all National Emission Standards for Hazardous Air Pollutants (NESHAP) source categories subject to a Subpart as listed below.

   b. Subpart R – NESHAP for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), applies as specified under Subpart CC.

   c. Subpart CC – NESHAP Pollutants from Petroleum Refineries shall apply to, but not be limited to, the bulk loading racks.

   d. Subpart UUU – NESHAP Pollutants from Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Plants, shall apply to, but not be limited to, the FCCU and the Catalytic Reformer Unit.

   e. Subpart EEEE – NESHAP for Organic Liquids Distribution (non-gasoline) shall apply to, but not be limited to, Tank #1 (DEGME) and the naphtha loading racks.

   f. Subpart DDDDD – NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, applies to all boilers and process heaters as specified in Subpart DDDDD.

      Boiler #4 is expected to be a "temporary boiler" as defined for this subpart. Boiler #4 would become subject to this standard if any of the following conditions are determined:

      - Boiler #4 remained on location for more than 12 months, or
      - Boiler #4 is attached to a foundation, or
      - Boiler #4 is moved from one location to another in an attempt to circumvent the 12 month residence time.

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. Calumet must demonstrate compliance with the ambient air quality standards based on the use of Good Engineering Practices (GEP) stack height.

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

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

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

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

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

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

2. <u>ARM 17.8.743 Montana Air Quality Permits--When Required</u>. This rule requires a person to obtain an air quality permit or permit modification to construct, modify, or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. Calumet has a PTE greater than 25 tons per year of PM, NO_x, CO, VOC, and SO_2; therefore, an air quality permit is required.

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

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

5. <u>ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements</u>. (1) This rule requires that a permit application be submitted prior to installation, modification or use of a source. Calumet submitted the required permit application for the current permit action. (7) This rule

requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. Calumet submitted an affidavit of publication of public notice for the April 12, 2017 issue of *Great Falls Tribune,* a newspaper of general circulation in Great Falls, Montana in Cascade County, as proof of compliance with the public notice requirements.

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

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

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

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

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

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

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

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

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

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

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

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

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

   Calumet's existing petroleum refinery in Great Falls is defined as a "major stationary source" because it is a listed source with the PTE more than 100 tons of several pollutants (PM, SO_2, NO_x, CO, and VOC).

   This permit modification is associated with the major modification authorized by the issuance of MAQP #2161-29 that resulted in a net emission increase greater than the significance levels for GHG and VOC. This permit action re-evaluates that project's emissions based on a proposed alternative operating scenario and maintains the project emissions below the relevant significant emission rates.

H. ARM 17.8, Subchapter 9 – Permit Requirements for Major Stationary Sources or Modifications Located within Nonattainment Areas, including, but not limited to:

1. ARM 17.8.904 When A Montana Air Quality Permit Required. This rule requires that major stationary sources or major modifications located within a nonattainment area must obtain an MAQP in accordance with the requirements of this subchapter, as well as the requirements of Subchapter 7.

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

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

   a. PTE > 100 TPY of any pollutant;

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

   c. PTE > 70 TPY of particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}) in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing MAQP #2161-30 for Calumet, the following conclusions were made:

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

   b. The facility's PTE is greater than 10 TPY for a single HAP and greater than 25 TPY of combined HAPs.

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

   d. This facility is subject to NSPS requirements (40 CFR 60, Subparts A, J, Ja, Dc, Kb, UU, VV, VVa, GGG, GGGa, and QQQ).

   e. This facility is subject to current NESHAP standards (40 CFR 63, Subparts A, R, CC, UUU, EEEE, ZZZZ).

   f. This source is not a Title IV affected source.

   g. This facility is not a solid waste combustion unit.

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

   Based on these facts, the Department determined that Calumet is a major source of emissions as defined under Title V.

   Calumet did not submit a concurrent Title V Operating Permit Application with this permit action, but pursuant to ARM 17.8.1205, Calumet is required to file a complete application for an air quality operating permit within 12 months after commencing operation of project-related emission units.

III. BACT Analysis

A BACT determination is required for each new or modified source. Calumet shall install on the new or modified source the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. BACT analysis was required only for those units which were not originally included in MAQP #2619-29.

Boiler #4 (Temporary Boiler) BACT Review:

Boiler #4 will be fired on only natural gas. The primary pollutants of concern for natural gas fired boilers are NO_X and CO. Pipeline quality natural gas combustion is inherently low in SO_2, PM, and VOC emissions.

NO_X Emissions

NO_X is formed by three mechanisms: thermal NO_x, fuel NO_x, and prompt NO_x. In natural gas combustion, NO_X is primarily produced via the thermal and prompt NO_x mechanisms.

Thermal NO_x results from the high temperature thermal dissociation and subsequent reaction of combustion air molecular nitrogen and oxygen. Thermal NO_x 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 oxygen concentration, peak temperature, and the duration at peak temperature. As these three factors increase in value, the rate of thermal NO_x generation increases.

During combustion of hydrocarbon fuels, the NO_x formation rate can exceed that produced from direct oxidation of nitrogen molecules, due to 'prompt NO_x'. Prompt NO_x is usually a very small fraction of overall potential NO_x emissions levels in natural gas-fired combustion equipment, although the prompt NO_x mechanism can become a larger factor of NO_X emissions in lower temperature, fuel rich, short residence time designs (i.e – Ultra Low NO_x burner designs). Prompt NO_x plays a factor in limiting the NO_x emissions reductions achievable through typical combustion controls, however, because Prompt NO_x is a small part of overall potential NO_x emissions, its presence does not override the effectiveness of utilizing combustion controls that limit thermal NO_x formation.

Fuel NO_x is formed by the direct oxidation of nitrogen compounds contained in a fuel stream. Therefore, fuel NO_x related emissions increase with an increase in the quantity of nitrogen-containing compounds present in a fuel. Pipeline quality natural gas is inherently low in fuel bound nitrogen.

Ultra-Low NO_X Burners (ULNB) and Flue Gas Recirculation (FGR):

ULNB and FGR are combustion controls that reduce the formation of NO_X at the source, and are typically used together. These combustion controls reduce peak flame temperatures, and help provide for a fuel rich (reducing) atmosphere in the primary combustion zone, reducing the amount of Thermal NO_x formed.

Selective Catalytic Reduction:

Selective Catalytic Reduction (SCR) is a post-combustion treatment which reduces oxides of nitrogen to molecular nitrogen, water, and oxygen via utilization of ammonia or urea as a reducing agent and a catalyst. SCR has been demonstrated to achieve high levels of NO_x reduction, up to 90%. In general, SCR typically presents economic challenges in being applied to this size of boiler firing natural gas, and the Department concurred without further review that SCR would not constitute BACT.

Selective Non-Catalytic Reduction:

Selective Non-Catalytic Reduction (SNCR) is a post-combustion treatment which is similar to SCR in that this technology utilizes ammonia or urea to reduce oxides of nitrogen, but does so without use of a catalyst. Because no catalyst is utilized in this technology, the temperatures required are usually over twice as high, typically requiring temperatures ranging between 1600°F and 2100°F. Also, reduction efficiency is reduced, as this control technology typically provides up to only a 50% reduction. In general, SNCR typically presents economic challenges in being applied to this size of boiler firing natural gas, and the Department concurred without further information request that this technology would not constitute BACT.

Calumet proposed that BACT for this boiler for NO_X is use of ultra-low NO_X burners, meeting an emission limit of 0.039 lb/MMBtu. In review of the RACT/BACT/LAER clearinghouse and other BACT determinations, the Department determined that this emissions rate meets BACT.

CO and VOC Emissions

CO and VOC emissions result from the incomplete combustion of organic compounds. Higher temperatures, higher residence times, and increased oxygen levels generally result in more complete combustion and therefore less CO and VOC emissions, however, such efforts can also result in increased NO_X emissions. Generally speaking, ambient air quality standards for NO_2 are much more stringent than CO standards, with the one hour ambient NO_2 standard being 100 parts per billion and the CO one hour standard being 35 part per million. Therefore, a certain amount of tradeoff of maximizing reduction of NO_X emissions compared to maximizing reduction of CO emissions may be acceptable to provide an overall best impacts scenario from an environmental impacts standpoint. Further, as is demonstrated for this boiler, proper operation and design of a boiler equipped with ultra-low NO_X technology can provide for high levels of NO_X performance while maintaining low levels of CO and VOC emissions.

An overview of the BACT review for this boiler is presented below:

Thermal Oxidation:

By creating a high temperature environment (usually at least 1500°F), thermal oxidizers complete conversion of CO and VOC to CO_2 and water. Such technology is capable of reducing VOC emissions by up to 99%, and CO emissions up to 90%. However, the costs associated with such technology are prohibitive for a boiler of this size and type. The

Department removed thermal oxidation from further consideration for BACT for this application without further information required.

Catalytic Oxidation

Catalytic Oxidizers utilize a catalyst to lower the temperature required to ensure complete oxidation, generally about 800 °F. However, the costs associated with such technology are usually prohibitive for a boiler of this size and type. The Department removed catalytic oxidation from further consideration for BACT for this application without further information required.

Proper System Design and Operation:

The manufacturer of this boiler design offers an emissions guarantee of 0.040 lb/MMBtu of CO, while also guaranteeing a NO_X emissions standard of 0.039 lb/MMBtu under the same conditions. Such emissions level requires a certain level of proper operations, maintenance, and design.

With a CO limit as proposed, the associated CO testing prescribed, and the known relationship between pollutants, no VOC limit and likewise no additional VOC monitoring was deemed necessary as required BACT permit conditions. The Department concluded that proper operation and design, meeting a CO emission limit of 0.040 lb/MMBtu, meets BACT for CO and VOC.

SO_2 Emissions:

Pipeline quality natural gas has very low sulfur content. Any additional add on control would be expected to be cost-prohibitive. Calumet has proposed and the Department has accepted that the burning of pipeline quality natural gas only constitutes BACT for SO_2.

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

Particulate controls are rarely, if ever, applied to natural gas fired boilers, due to the low level of potential emissions from such sources. The Department agreed that burning pipeline quality natural gas meets BACT for PM, PM_{10}, and $PM_{2.5}$.

Ammonia Combustor BACT Review

NO_X Emissions

NO_x would be generated as a combination of assist gas and ammonia (NH_3) waste gas is combusted. The supplemental fuel, purchased natural gas, is mainly methane (CH_4) and is not expected to make a significant contribution to the NO_x emissions. NO_x emissions are formed by three mechanisms during combustion: thermal NO_x, fuel NO_x, and prompt NO_x. Total NO_x emissions from the ammonia combustion unit are not expected to exceed 2.8 ton per year.

Thermal NO_x is generated in the high temperature zone near the burner of a combustion device due to the dissociation and subsequent reaction of combustion air molecular nitrogen and oxygen. Thermal NO_x is typically the dominant formation mechanism for gaseous fuels that contain little inherent nitrogen. Thermal NO_x formation increases as oxygen concentration, burner temperature, or retention time at elevated burner temperature.

Fuel NO_x is formed by the direct oxidation of nitrogen compounds contained in a fuel stream. Fuel NO_x related emissions increase with an increase in the quantity of nitrogen-containing compounds present in the fuel. Typically fuel NO_x comprises a small portion of the total NO_x generated from gaseous fuel combustion; however, the NH_3 concentration in the sour water stripper overhead gas streams routed to the proposed ACU could make fuel NO_x more significant in this application.

Lastly, prompt NO_x is formed when molecular nitrogen in the air combines with fuel in a fuel-rich environment. Prompt NO_x formation increases in lower temperature, fuel rich, and short residence time combustion environments.

The following paragraphs summarize the NOx emission controls evaluated for the proposed ACU:

Selective Catalytic Reduction (SCR)

The primary benefit of an SCR system is that it is a post-combustion technology that can reduce NOx emissions 70 to 90 percent regardless of whether the pollutant was formed through the fuel or thermal pathways. There are disadvantages to using the SCR control technology, the first being the additional space required for the installation of a catalyst reactor vessel, ammonia storage, vaporization, and injection equipment. The CMR refinery in Great Falls has limited space available within the process areas of the refinery for installation of equipment.

The second disadvantage is the ammonia required, in either a liquid solution or anhydrous form, for the operation of the SCR technology. It is difficult to handle this potentially hazardous material and could potentially increase the ammonia emissions from the stack via ammonia slip.

The third disadvantage with using the SCR control technology is the cost. Capital costs to purchase and install the technology along with the costs of operation of an SCR system can be cost prohibitive for small thermal oxidizers. Upon review of Environmental Protection Agency's (EPA's) RACT/BACT/LAER Clearinghouse (RBLC) database, only one of eleven thermal oxidizers utilized the SCR control technology, and that unit had a maximum rated heat input capacity of 72 million British thermal units per hour (MMBtu/hr), which is considerably larger than the proposed ACU (8 MMBtu/hr). SCR was removed from further consideration for BACT based on energy, environmental, and cost considerations.

Selective Non-Catalytic Reduction (SNCR)

Similar to SCR, SNCR is a post-combustion control technology that can reduce NO_x emissions up to 50 percent. SNCR reduces both thermal and fuel NO_x emissions in the emission stack, but has many of the same disadvantages as SCR. like SCR, SNCR would require additional space, NH_3 or urea handling, high capital investment, and potentially result in additional NH_3 emissions.

SNCR does not use a catalyst to reduce the temperature required to convert NO_x to nitrogen and water; therefore, the exhaust gas temperature would need to be maintained within the optimal range depending on the reducing agent selected. The manufacturer design specifications indicate the burner temperature is 1,800° F which is at the lower end of the optimal range for NH_3 injection.

Since there are quest ions pertaining to whether or not SNCR would be able to operate in the optimal range and the same environmental and cost concerns exist as with SCR, SNCR was removed from further consideration as BACT for the proposed ACU.

Low NO_x Burner (LNB):

LNB, implemented in the combustion chamber, targets the reduction of NO_x emissions formed through the thermal pathway by controlling the temperature and oxygen concentration locally at the burner. This control technology can potentially reduce NO_x emissions 40 to 60 percent. The primary consideration for this technology would be the cost of implementation.

Staged Combustion

Staged combustion is a control technology implemented in the combustion chamber to reduce the formation of NO_x formed through the thermal and fuel pathways. This control technology differs from LNB that it focuses primarily on reduction of thermal NO_x through local burner temperature and oxygen concentration control. Since the treated gas will contain fuel bound nitrogen in the form of NH_3, this technology would be favorable to reduce fuel NO_x.

By itself the use of staged combustion can achieve 40 percent reduction of NO_x emissions. As with LNB, the primary consideration for this technology would be the cost of implementation. Since the proposed ACU waste gas stream contains fuel bound nitrogen in the form of NH_3, supplementing LNB with staged combustion would decrease NO_x emissions formed through the fuel pathway. Calumet has determined that using LNB in combination with staged combustion will achieve a NO_x emission rate of 61 ppmv and a vendor certified NH_3 emission rate of 10 ppmv at 3 percent oxygen. These NO_x and NH_3 concentrations are consistent with the concentrations accepted as BACT for a thermal oxidizer used in this same manner.

CO, VOC, PM, $PM_{2.5}$ and PM_{10} Emissions

The combustion of ammonia would not be expected to produce high emissions of CO, VOC or $PM/PM_{2.5}/PM_{10}$. Although the stream may have a small amount of hydrocarbon impurities, the ammonia does not have carbon to create CO or CO_2 emissions in combustion. Natural gas would be the main contributor; emissions were determined using the AP-42 emission factors for natural gas are
known to be overestimated as a result. Additional controls would be cost prohibitive considering the low emissions estimated for uncontrolled emissions of CO, VOC and $PM/PM_{2.5}/PM_{10}$.

SO_2 Emissions

The combustion of ammonia would not be expected to produce much uncontrolled emissions of SO_2, especially since this stream has been pre-treated to meet the requirements of 40 CFR 60 Subpart Ja for sulfur compounds. Contributions from the supplemental fuel will be low considering that purchased natural gas is inherently low in sulfur compounds. For emission inventory purposes the fuel gas emission limits in 40 CFR 60 Subpart Ja were used in the calculation of SO_2 emissions and rendered a small amount of SO_2 emissions. No further analysis of control technologies for SO_2 emissions is being considered.

Proposed Emission Controls

Calumet selected the following emission controls based on BACT considerations, environmental impact, techno logical feasibility and economic feasibility.

NOx - Low NOx burner with staged combustion.

CO, VOC or $PM/PM_{2.5}/PM_{10}$ - No further controls beyond good combustion practices.

SO_2 - No further controls beyond the use of purchased natural gas and pre-treating the stream to meet the emission limits of 40 CFR 60 Subpart Ja.

IV. Emission Inventory

The current permit action establishes emissions limitations to maintain the project as a minor project for NO_x and CO with respect to the prevention of significant deterioration thresholds. The following emissions tables are presented by pollutant to demonstrate the netting analyses associated with this action and the determination of the 'umbrella' limitations made to maintain the project status as a minor project with respect to Prevention of Significant Deterioration thresholds.

As a look-back action, this action uses the same baseline period as was undertaken in MAQP #2161-29. Calendar years 2011 and 2012 were selected as the representative baseline period. In the original permitting action, Calumet originally suggested that 2010 and 2011 be used. The Department indicated that the most recent 2 year period (2012 and 2013) should be used unless Calumet provided justification otherwise. Calumet requested 2013 not be considered representative normal operations due to a refinery shutdown during that timeframe. As a result, calendar years 2011 and 2012 were selected as the baseline period.

NO_x Emissions Summary

Calumet Expansion Project - Project Level Emissions Increases		
Project Related Unit	**NOx**	**Comments**
New Emitting Units (PTE):		
Crude 2 Atmospheric Heater (H-2101)	10.88	PTE
Crude 2 Vacuum Heater (H-2102)	4.14	PTE
Combined Feed Heater (H-4101)	8.28	PTE
MHC Reactor Fractionation Heater (H-4102)	5.83	PTE
#3 (15MM) Hydrogen Plant Reformer A	14.97	PTE
#3 (15MM) Hydrogen Plant Reformer B	14.97	PTE
Emergency Flare	6.69	Pilot + constant positive pressure gas + conservative assumption of constant hydrogen gas + 9 hrs vent gas permit limit
Temporary Boiler	39	PTE @ 1000 Btu/scf
Ammonia Combustor	2.79	New Unit proposed to reduce Refinery Fuel Gas Nitrogen Content
Boiler #3 - MAQP #2161-25	5.03	PTE - Determined related to this project.
Existing Project Affected Emitting Units:		Assume future actuals = PTE except flare is +10% of 2016 actuals
Kerosene Heater	0.4	= 4.11 PTE - 3.71 Actuals
DSL/GO HDS Heater	2.24	= 6.21 PTE - 3.97 Actuals
Railcar Loading	0.95	= PTE - actuals
Flare #1 Increases	13.77	= 19.37 + 0.64 - actuals ((7.28+5.21) / 2)
Project Related Emissions Increase:	**129.93**	(Greater than 40 TPY SER, netting required)

NO_x Contemporaneous Increases and Decreases: (5 years from 8/19/2014 – expansion startup date)		
Action	**NOx**	**Comments**
MSAT Heaters H-402 and H-405 (de minimis action approved 1/27/2011)	1.77	startup date: 9/12/2012.
Tank Heaters in 130, 132, 133 - MAQP #2161-23	0.21	2 yr average
Removal of H-0402	-1.1	shut down 9/1/2013.
Total Contemporaneous Increases and Decreases:	0.88	

Project Related Increases:	129.93
Contemporaneous Changes:	0.88
TOTAL:	130.81
Amount of Needed Reductions:	90.81
With 5 TPY safety factor:	95.81

PSD Avoidance NO_X Umbrella Limit Calculation in TPY (Offsets)			
Existing Emitting Unit	**2011 Actual Emissions**	**2012 Actual Emissions**	**2 Year Average Actual Emissions**
Boiler #1	48.15	27.55	37.85
Boiler #2	42.61	25.62	34.12
CDU #1 Atmospheric Heater H-0101 ("Crude Furnace" in annual EI)	19.88	21.84	20.86
CDU #1 Vacuum Heater H-0102 ("Vacuum Heater" in annual EI)	2.66	3.15	2.91
New Units to Include In Umbrella			**PTE**
Temporary Boiler			39.00
Boiler #3			5.03
Crude #2 Atmospheric Heater (H-2101)			10.88
Crude #2 Vacuum Heater (H-2102)			4.14
Combined Feed Heater (H-4101)			8.28
MHC Reactor Fractionation Feed Heater (H-4102)			5.83
#3 (15MM) Hydrogen Plant Reformer A			14.97
#3 (15MM) Hydrogen Plant Reformer B			14.97

PSD Avoidance NO_X Umbrella Limit Calculation in TPY (Offsets)			
Existing Emitting Unit	**2011 Actual Emissions**	**2012 Actual Emissions**	**2 Year Average Actual Emissions**
Reduction for PSD Avoidance Purposes plus 5 TPY safety factor:			95.81
TOTAL NO_X Umbrella Limit:	-	-	***103.02***

CO Emissions Summary:

Calumet Expansion Project - Project Level Emissions Increases		
Project Related Unit	**CO**	**Comments**
New Emitting Units (PTE):		
Crude 2 Atmospheric Heater (H-2101)	17.10	PTE
Crude 2 Vacuum Heater (H-2102)	6.50	PTE
Combined Feed Heater (H-4101)	13.01	PTE
MHC Reactor Fractionation Heater (H-4102)	9.15	PTE
#3 (15MM) Hydrogen Plant Reformer A	8.80	PTE
#3 (15MM) Hydrogen Plant Reformer B	8.80	PTE
Emergency Flare	4.94	PTE
Temporary Boiler	15.64	PTE @ 1,000 Btu/scf
Ammonia Combustor	3.07	PTE
Boiler #3 - MAQP #2161-25	9.01	PTE
Existing Project Affected Emitting Units		Assume future actuals = PTE, except flare assumes 10% increase from 2016
Kerosene Heater	0.10	35 lbs/MMScf and 1000 Btu/scf, PTE - actual
DSL/GO HDS Heater	2.91	= 3.46 PTE - 0.55 Actuals
Railcar Loading	2.85	206 million gallons PTE - Average of 14.601 and 17.681 million gallons in 2011 and 2012 respectively, 0.03 lbs CO/1,000 gal
Flare #1 Increases	31.77	= 38.75 + 5.52 (low and high Btu Flaring) - 12.49 actuals
Project Related Emissions Increase:	***133.65***	> 100 TPY SER, therefore netting required

CO Contemporaneous Increases and Decreases: (5 years from 8/19/2014)		
Action	**CO**	**Comments**
MSAT Heaters (de minimis action approved 1/27/2011 - submittals 12/15/2010 and 1/13/2011)	2.83	Start-up date: 9/12/2012.
Tank Heaters in 130, 132, 133 - MAQP #2161-23	0.05	2 yr average
Removal of H-0402	-0.27	shut down 9/1/2013
Total Contemporaneous Increases and Decreases:	*2.61*	

Project Related Increases:	133.65
Contemporaneous Changes:	2.61
TOTAL:	136.26
Amount of Needed Reductions:	36.26
With 5 TPY safety factor:	41.26

PSD Avoidance CO Umbrella Limit Calculation in TPY (Offsets)			
Existing Emitting Unit	**2011 Actual Emissions**	**2012 Actual Emissions**	**2 Year Average Actual Emissions**
Boiler #1	1.34	1.16	1.25
Boiler #2	1.19	1.08	1.14
CDU #1 Atmospheric Heater H-0101 ("Crude Furnace" in annual EI)	4.97	5.46	5.22
CDU #1 Vacuum Heater H-0102 ("Vacuum Heater" in annual EI)	0.67	0.79	0.73
New Units to Include In Umbrella			**PTE**
Temporary Boiler			15.64
Boiler #3			9.01
Crude #2 Atmospheric Heater (H-2101)			17.10
Crude #2 Vacuum Heater (H-2102)			6.50

PSD Avoidance CO Umbrella Limit Calculation in TPY (Offsets)			
Existing Emitting Unit	**2011 Actual Emissions**	**2012 Actual Emissions**	**2 Year Average Actual Emissions**
Combined Feed Heater (H-4101)			13.01
MHC Reactor Fractionation Feed Heater (H-4102)			9.15
#3 (15MM) Hydrogen Plant Reformer A			8.80
#3 (15MM) Hydrogen Plant Reformer B			8.80
Reduction for PSD Avoidance Purposes plus 5 TPY safety factor:			41.26
TOTAL CO Umbrella Limit:	-	-	***55.08***

$PM/PM_{10}/PM_{2.5}$ Emissions Summary:

Calumet Expansion Project - Project Level Emissions Increases				
Project Related Unit	**PM(fil)**	**PM_{10} (cond+fil)**	**$PM_{2.5}$ (cond+fil)**	**Comments**
New Emitting Units (PTE):				
Crude 2 Atmospheric Heater (H-2101)	0.06	0.16	0.13	PTE - 0.0002 lb/MMBtu PM and PM_{10} Filterable, 0.00011 lb/MMBtu $PM_{2.5}$ filterable, 0.0031 lb/MMBtu condensable via Roy Huntley EPA Region 5 EFs for refinery fuel gas
Crude 2 Vacuum Heater (H-2102)	0.02	0.06	0.05	
Combined Feed Heater (H-4101)	0.05	0.12	0.10	

Calumet Expansion Project - Project Level Emissions Increases				
Project Related Unit	**PM(fil)**	**PM_{10} (cond+fil)**	**$PM_{2.5}$ (cond+fil)**	**Comments**
MHC Reactor Fractionation Heater (H-4102)	0.03	0.08	0.07	
#3 (15MM) Hydrogen Plant Reformer A	0.06	0.15	0.12	
#3 (15MM) Hydrogen Plant Reformer B	0.06	0.15	0.12	
Emergency Flare	0	0	0	Negligible amounts of PM are assumed for non-smoking flares. 0% opacity is required
Temporary Boiler	0.08	0.20	0.16	PTE via Roy Huntley EPA Region 5 EFs
Ammonia Combuster	0.07	0.26	0.26	PTE using same EFs as Heaters
Boiler #3 - MAQP #2161-25	0.05	0.14	0.11	PTE using same EFs as Heaters
Existing Project Affected Emitting Units (PTE - Actual):	**PM(fil)**	**PM_{10} (cond+fil)**	**$PM_{2.5}$ (cond+fil)**	Assume PTE for future actual
Kerosene Heater	0.00	0.00	0.00	PTE - actual, Roy Huntley Efs
DSL/GO HDS Heater	0.01	0.02	0.02	
Railcar Loading	0.00	0.00	0.00	negligible emissions
Flare #1	0.00	0.00	0.00	negligible emissions
Project Related Emissions Increase:	***0.50***	***1.34***	***1.15***	SER = 25, 15, and 10. No netting required.
NO_X Triggered $PM_{2.5}$?			***No***	Secondary $PM_{2.5}$ if NO_X > 40 TPY
SO_2 Triggered $PM_{2.5}$?			***No***	Secondary $PM_{2.5}$ if SO_2 > 40 TPY

SO_2 Emissions Summary:

Calumet Expansion Project - Project Level Emissions Increases		
Project Related Unit	**SO_2**	**Comments**
New Emitting Units (PTE):		
Crude 2 Atmospheric Heater (H-2101)	2.89	PTE
Crude 2 Vacuum Heater (H-2102)	1.1	PTE
Combined Feed Heater (H-4101)	2.2	PTE
MHC Reactor Fractionation Heater (H-4102)	1.55	PTE
#3 (15MM) Hydrogen Plant Reformer A	0.17	PTE
#3 (15MM) Hydrogen Plant Reformer B	0.17	PTE
Emergency Flare	9.77	PTE
Temporary Boiler	0.24	PTE
Ammonia Combustor	0.44	PTE
Boiler #3 - MAQP #2161-25	7.66	PTE based on MAQP BACT
Existing Project Affected Emitting Units (PTE - Actual):		
Kerosene Heater	0.59	= 0.79 PTE - 0.2 Actuals
DSL/GO HDS Heater	2.1	= 2.39 PTE - 0.29 Actuals
Railcar Loading	0	negligible
Flare #1 Increases	0	Past Actuals are higher than future actuals because of NSPS Ja
Project Related Emissions Increase:	***28.88***	(Less than 40 TPY SER, no netting required)

VOC Emissions Summary

Calumet Expansion Project - Project Level Emissions Increases		
Project Related Unit	**VOC**	**Comments**
New Emitting Units (PTE):		
Crude 2 Atmospheric Heater (H-2101)	0.8	PTE
Crude 2 Vacuum Heater (H-2102)	0.3	PTE
Combined Feed Heater (H-4101)	0.61	PTE
MHC Reactor Fractionation Heater (H-4102)	0.43	PTE
#3 (15MM) Hydrogen Plant Reformer A	1.58	PTE
#3 (15MM) Hydrogen Plant Reformer B	1.58	PTE
Emergency Flare	1.75	PTE
Temporary Boiler	2.16	PTE
Ammonia Combustor	3.07	PTE
Boiler #3	0.68	PTE
New Tanks TK-201, 202, 143, 144b, 186	5.23	PTE new tanks
Wastewater Drains	7.03	New
New DAF Unit	1.18	based on 2016 flow and effluent conc data, with 90% control applied

Fugitive Sources - Pumps, Valves, Connectors, Etc.	17.4	Uses 2015 protocol, 250 ppm consent decree leak rate assumed for all components
Emergency Flare	1.75	PTE by permit
Non-Modified Project Affected Emitting Units:		Assume future actuals = PTE except flare
Flare #1	14.54	= 20.78 - ((7.28+5.21)/2)
Kerosene Heater	0.01	= 0.08 PTE - 0.07 actuals
DSL/GO HDS Heater	0.12	= 0.23 PTE - 0.11 actuals
Railcar Loading	1.08	= 1.22 - 0.14
Tank TK-126	0.60	= 3859.06 lb/yr - 2655.64 lb/yr. All other changes are non-creditable reductions
Existing Wastewater Units	4.11	based on updated information
Project Related Emissions Increase:	***66***	> SER of 40 TPY

Contemporaneous Increases and Decreases: (5 years from 8/19/2014)		
Action	**VOC**	**Comments**
MSAT Heaters (de minimis action approved 1/27/2011)	3.57	startup date: 9/12/2012
Tank Heaters in 130, 132, 133 - MAQP #2161-23	0.05	confirm actual emissions
Removal of H-0402	-0.38	Shut-down 9/1/2013.
TOTAL Contemporaneous Increases and Decreases:	***3.24***	

TOTAL for MAQP #2161-30:	**69.24**
Previously Reviewed Emissions Total (MAQP 2161-29):	**77.19**
Emissions Difference MAQP #2161-30 minus 2161-29	**-7.95**

V. Existing Air Quality

As of July 8, 2002, Cascade County is designated as an Unclassifiable/Attainment area for NAAQS for all criteria pollutants. Previous to that date, Calumet was located outside, but adjacent to, a CO nonattainment area in downtown Great Falls. On December 2, 1985, the Department of Environmental Quality (formerly Montana Department of Health and Environmental Sciences) and Calumet (formerly Montana Refining Company) signed a stipulation requiring Calumet to obtain an air quality permit and stipulating a permit emission limitation of 4,700 TPY CO, when considered in conjunction with control measures on other sources such as automobiles, would achieve compliance with ambient CO standards. This permit limits plant-wide CO emissions to 4,700 TPY.

In 1993, the Department conducted preliminary ambient air quality modeling for SO_2 using the COMPLEX1 and ISC2 models and meteorological data collected from the Great Falls Airport assuming 7 tons per day of SO_2 emissions. The results of the model previously demonstrated that at 7 tons per day of emissions, this facility causes a violation of the state and federal SO_2 ambient standards. As a result, Calumet was limited to 5.25 tons per day of plant-wide refinery SO_2 emissions (MAQP #2161-06) in the first step of a plan to achieve attainment. In April 1998, Calumet submitted additional modeling to demonstrate compliance with the NAAQS for SO_2. In June 1999, this modeling, and the permit application were determined to be complete. The permitting action established limitations that demonstrate compliance with the NAAQS and MAAQS for SO_2. The facility is now limited to 4.15 tons per rolling 24-hours of plant-wide refinery SO_2 emissions (or 1515 TPY). An ambient air-monitoring plan will continue to be used to monitor SO_2 emissions.

VI. Ambient Air Impact Analysis

An ambient air impact analysis was not required for this permit action because this permit has established an allowable net emissions increase which is less than the modeling thresholds and/or less than previously reviewed emissions increases for this project. As an action which does not trigger Prevention of Significant Deterioration permitting requirements, the action is considered a minor permitting action. The Department is not aware of any special circumstances in which this area would be expected to be affected beyond allowable ambient air quality levels as the result of a minor permitting action.

VII. Incinerator Review

The purpose of the ammonia combustor is to thermally oxidize process waste gas from sour water stripper overhead after treatment. The Department determined the unit meets the definition of an incinerator as described at MCA 75-2-103(12) and as such is subject to the incinerator requirements of MCA 75-2-215 and ARM 17.8.770.

The proposed ammonia combustor has a heat input capacity of 8.0 MMBtu/hr. The Department has reviewed a detailed human health risk assessment for a similar combustor which was over 3 times larger. In this review, the Department noted that even given a conservative approach on estimating potential HAP emissions (the HAP emissions are over estimated on a lb/MMBtu basis), the human health risk assessment concluded that ambient concentrations of all HAPs were significantly below any levels of concern.

The ammonia combustor will be equipped with a 30 foot high stack, with an average velocity of 20 feet per second, with velocities higher at higher firing rates. The unit will burn only ammonia enriched fuel gas and supplemental natural gas. The unit's HAP emissions would be expected to be similar to that of an 8 MMBtu/hr natural gas fired boiler. The Department can easily conclude based on a qualitative review and human health risk assessment experience that no more than a negligible risk to human health would be expected.

However, to further investigate and ensure an appropriate analysis has been undertaken, a Screen 3 model run was conducted. An emissions rate of 0.02 grams per second (the total HAP emissions rate) was modeled from a 30 foot (9.144 meter) stack with a 0.89 meter inside diameter with an average flow rate of 8,115 actual cubic feet per minute. A stack temperature of 922 Kelvin was assumed. A maximum 1 hr concentration of 0.89 micrograms per cubic meter at 172 meters was calculated. The 1-hr concentration was converted to an annual concentration by multiplying by a factor of 0.10 in accordance with EPA's *Screening Procedures for Estimating the Air Quality Impact of Stationary Sources*, providing for a combined HAPs concentration of 0.089 micrograms per cubic meter. The resulting speciated concentrations compared to the de minimis levels of Table 1 and Table 2 are provided below:

HAP	grams/sec	Fraction of Total	ug/m^3	Table 1 Cancer Annual De Min Level	Table 2 Noncancer Chronic Annual De Min Level	Table 2 Noncancer Acute Annual De Min Level
Arsenic	1.98E-07	1.06E-04	9.44E-06	2.33E-05	5.00E-03	
Benzene	2.08E-06	1.11E-03	9.91E-05	1.20E-02	7.10E-01	
Benzo(a)anthracene	1.78E-09	9.53E-07	8.48E-08	5.88E-05		
Benzo(b)fluoranthene	1.78E-09	9.53E-07	8.48E-08	5.88E-05		
Benzo(a)pyrene	1.19E-09	6.37E-07	5.67E-08	5.88E-05		
Beryllium	1.19E-08	6.37E-06	5.67E-07	4.17E-05	4.80E-05	
Cadmium	1.09E-06	5.84E-04	5.20E-05	5.56E-05	3.50E-02	
Chromium	1.38E-06	7.39E-04	6.58E-05	8.33E-06	2.00E-05	
Dibenz(ah)anthracene	1.19E-09	6.37E-07	5.67E-08	5.88E-05		
Dichlorobenzene	1.19E-06	6.37E-04	5.67E-05	9.09E-03	8.00E+00	
Formaldehyde	7.41E-05	3.97E-02	3.53E-03	7.69E-03	3.60E-02	3.70E+00
n-Hexane	1.78E-03	9.53E-01	8.48E-02			
Indeno(123-cd)pyrene	1.78E-09	9.53E-07	8.48E-08	5.88E-05		
Lead	4.94E-07	2.65E-04	2.35E-05		1.50E-02	
Manganese	3.76E-07	2.01E-04	1.79E-05		5.00E-04	
Mercury	2.57E-07	1.38E-04	1.22E-05		3.00E-03	3.00E-01
Naphthalene	6.03E-07	3.23E-04	2.87E-05		1.40E-01	
Nickel	2.05E-06	1.10E-03	9.77E-05	3.85E-04	2.40E-03	1.00E-02
POM	8.72E-08	4.67E-05	4.16E-06	5.88E-05	7.10E-01	
Toluene	3.36E-06	1.80E-03	1.60E-04		4.00E+00	
Selenium	2.37E-08	1.27E-05	1.13E-06		5.00E-03	2.00E-02

As demonstrated above, all pollutants are below the de minimis levels of Table 1 and Table 2 of ARM 17.8.770. The impacts of existing emissions and the synergistic effect of combined pollutants were not considered in the final human health risk level calculated to determine compliance with the negligible risk standard. Environmental effects unrelated to human health were not considered in determining compliance with the negligible risk standard, but were evaluated as required by the Montana Environmental Policy Act, in determining compliance with all applicable rules or other requirements requiring protection of public health, safety, and welfare and the environment.

VIII. Taking or Damaging Implication Analysis

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

YES	NO	
X		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	X	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	X	3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)

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

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

IX. Environmental Assessment

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

DEPARTMENT OF ENVIRONMENTAL QUALITY
Air, Energy & Mining Division
Air Quality Bureau
1520 East Sixth Avenue
P.O. Box 200901
Helena, Montana 59620-0901
(406) 444-3490

ENVIRONMENTAL ASSESSMENT (EA)

Issued For: Calumet Montana Refining, LLC (Calumet)
1900 10th Street North East
Great Falls, MT 59404

Montana Air Quality Permit Number (MAQP): #2161-30

EA Draft: 9/26/2017
EA Final: 10/27/2017
Permit Final: 11/14/2017

1. *Legal Description of Site*: Calumet is located at 1900 10th Street N.E. in Great Falls, Montana. The legal description of the site is the NE¼ of Section 1, Township 20 North, Range 3 East, Cascade County, Montana.

2. *Description of Project*: This project revisits an expansion project originally permitted in MAQP #2161-29. In this project, Calumet would increase the low sulfur fuels capacity at the existing refinery from 10,000 barrels per stream day (BPSD) crude throughput up to 30,000 BPSD while increasing yields of distillates, kerosene, diesel, and asphalt products. The current project seeks to maintain or establish a synthetic minor status for oxides of nitrogen (NO_x) and carbon monoxide (CO) with respect to the Prevention of Significant Deterioration (PSD) program of the Administrative Rules of Montana (ARM) 17.8 Subchapter 8 for this project from a 'look-back' perspective. Most of the units associated with the expansion project have already been installed, and this action allows for inclusion of a new boiler, an ammonia combustor, and limitations which provide flexibility in where emissions can come from throughout the plant, provided an overall emissions cap is adhered to.

   The expansion project included the construction of four new processing units: a new crude unit that would process heavy sour crudes, a mild-hydrocracker (MHC) for gas-oil conversion to higher value distillates, a new hydrogen plant (#3) to support the MHC, and a fuel gas treatment unit to handle the increased fuel gas production from the MHC. The current project also allows for a temporary boiler (Boiler #4) and an ammonia combustor to be installed along with corresponding emissions limitations that keep the overall NO_x and CO emissions increases associated with this project to less than trigger levels that would require permitting in accordance with ARM 17.8 Subchapter 8.

   The specific emitting units included with the expansion project were: Hydrogen Plant #3 (equipped with two heaters and a total combined firing rating of up to 134 million British thermal units per hour (MMBtu/hr)); Combined Feed Heater (up to 54 MMBtu/hr); Fractionation Feed Heater (up to 38 MMBtu/hr), Crude Heater (up to 71 MMBtu/hr), Vacuum Heater (up to 27 MMBtu/hr), and a new secondary flare interconnected to the existing flare that would be equipped with a flare gas scrubber. With the expansion, Calumet also proposed to add a new rail car loading (diesel and asphalt) and unloading (crude oil and gas oil) area, and several new storage tanks in addition to re-purposing some existing storage tanks to accommodate the expansion project.

Additionally, the existing hydrotreating unit (HTU) that currently block operates in both diesel and gas-oil service would become the kerosene HTU, and the existing kerosene HTU will become a Naptha HTU. The addition of Boiler #4 and the ammonia combustor, and new limits to maintain the project as a minor increase in NO_x and CO emissions with respect to PSD significant emissions rate thresholds, allows Calumet continued operations of the expansion project while further NO_X emissions reductions from new and existing emitting units are established.

3. *Objectives of Project*: The primary purpose of the project would be to increase the low sulfur fuels capacity at the refinery from 10,000 barrels per stream day (BPSD) crude throughput up to 30,000 BPSD while increasing yields of distillates, kerosene, diesel, and asphalt products while maintaining or establishing a synthetic minor status for NO_x and CO with respect to the PSD permitting requirements.

4. *Additional Project Site Information*: This refinery has operated at this site since the 1930's. The refinery currently employs 115 people, and is located along the Missouri River in Great Falls, Montana.

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

6. *A Listing of Mitigation, Stipulations, and Other Controls*: A listing of the enforceable permit conditions and a permit analysis would be contained in MAQP #2161-30.

7. *Regulatory Effects on Private Property Rights*: The Department considered alternatives to the conditions imposed in this permit as part of the permit development. The Department determined the permit conditions would be reasonably necessary to ensure compliance with applicable requirements and to demonstrate compliance with those requirements and would not unduly restrict private property rights.

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

   A. Terrestrial and Aquatic Life and Habitats

   Calumet is an existing refinery operation proposing to expand at their current location. The refinery property is fenced for limited outside access. The project would occur within the existing refinery. The refinery is located near the river's edge. An increase in emissions of several criteria pollutants is associated with this project. Temporary construction activities would also be expected to take place.

Given the long history of operations at this facility and the magnitude of this project, and the limited amount of emissions increases which would be allowable under permit requirements, significant impacts would not be expected as a result of project approval.

B. Water Quality, Quantity, and Distribution

There would be a potential for impacts to groundwater or storm water due to spills and leaks, but these risks should be addressed in the facility's Spill Prevention Control and Countermeasures (SPCC) plan. Additionally, all surface water and collected groundwater would continue to be routed to the refinery wastewater system for treatment prior to discharge to the city's Publicly Owned Treatment Works (POTW). Such discharges are subject to regulation.

Given the long history of operations at this facility and the magnitude of this project, and the limited amount of emissions increases which would be allowable under permit requirements, significant impacts would not be expected as a result of project approval.

C. Geology and Soil Quality, Stability, and Moisture

The project would occur within the existing facility boundaries. During construction, there may be temporary and relatively minor disturbance to the area.

Given the long history of operations at this facility and the magnitude of this project, and the limited amount of emissions increases which would be allowable under permit requirements, significant impacts would not be expected as a result of project approval.

D. Vegetation Cover, Quantity, and Quality

Given the long history of operations at this facility and the magnitude of this project, and the limited amount of emissions increases which would be allowable under permit requirements, significant impacts would not be expected as a result of project approval.

E. Aesthetics

Given the long history of operations at this facility and the magnitude of this project, and the limited amount of emissions increases which would be allowable under permit requirements, significant impacts would not be expected as a result of project approval.

F. Air Quality

The project would take place at an existing and operating refinery. The amount of allowable emissions increases as a result of this project would be limited by permit. The area is currently designated as attainment/unclassifiable for all pollutants. A limited maintenance plan is in effect in the Great Falls area for carbon monoxide (CO) and CO is monitored in the area. The monitor information demonstrates the air quality in the area is in attainment for CO. Motor vehicle exhaust is known to be largest contributor of CO in the area. The current permit action would limit the allowable amount of increased CO emissions from this facility.

Given the long history of operations at this facility and the magnitude of this project, and the limited amount of emissions increases which would be allowable under permit requirements, significant impacts would not be expected as a result of project approval.

G. Unique Endangered, Fragile, or Limited Environmental Resources

The refinery has operated at this site since the 1930's. The refinery boundary is fenced. The permit required for this project would limit the amount of emissions increases allowable.

Given the long history of operations at this facility and the magnitude of this project, and the limited amount of emissions increases which would be allowable under permit requirements, significant impacts would not be expected as a result of project approval.

H. Sage Grouse Executive Order

The Department recognizes that the site location is not within a Greater Sage Grouse Habitat Areas as defined by Executive Order No. 12-2015.

I. Demands on Environmental Resources of Water, Air, and Energy

No significant additional demands on water resources would be expected for this project. There will be impacts to air resources with this project. The amount of allowable emissions increases associated with this project would be limited. There would likely be change in energy requirements, but this project would not require the facility to upgrade the electrical utilities.

Given the long history of operations at this facility and the magnitude of this project, and the limited amount of emissions increases which would be allowable under permit requirements, significant impacts would not be expected as a result of project approval.

J. Historical and Archaeological Sites

The proposed project would occur within the boundaries of the Calumet facility, a previously disturbed industrial site that has been in operation since the 1930s. The Montana State Historic Preservation Office previously informed the Department that there would be a low likelihood of adverse disturbance to any known archaeological or historic site, given previous industrial disturbance within a given area. Because there would be no additional ground disturbance, there would be no known effect on any historic or archaeological site. However, it is the Montana State Historic Preservation Office's stance that because the refinery itself is over 50 years old, a cultural resource inventory would be appropriate for modifications to take place on existing equipment.

Given the long history of operations at this facility and the magnitude of this project, and the limited amount of emissions increases which would be allowable under permit requirements, significant impacts would not be expected as a result of project approval. As a look-back project, only new units will be installed as a result of project approval.

K. Cumulative and Secondary Impacts

Additional emissions generated from the proposed project would result within the existing refinery facility, which has other sources of emissions that are much larger. This modification would be minor in comparison and the overall, cumulative and secondary impacts to the physical and biological aspects of the human environment would be minor.

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

A. Social Structures and Mores

The proposed project would not be expected to cause significant disruption to the social structures and mores in the area because the modification would occur within an existing and operating industrial source. Construction projects within the refinery would be visible and would cause some temporary disturbance to the surroundings. However, the facility would be required to operate according to the conditions that would be placed in the required air quality permit.

Given the long history of operations at this facility and the magnitude of this project, and the limited amount of emissions increases which would be allowable under permit requirements, significant impacts would not be expected as a result of project approval.

B. Cultural Uniqueness and Diversity

The predominant use of the area is an existing and operating refinery. Because the predominant use of this area has historically been refinery operations, there would not be a significant amount of impacts expected to result from this permit modification.

Given the long history of operations at this facility and the magnitude of this project, and the limited amount of emissions increases which would be allowable under permit requirements, significant impacts would not be expected as a result of project approval.

C. Local and State Tax Base and Tax Revenue

The permitting action would result in supporting a $400 million investment including equipment, labor and related construction costs. Positive impacts to the local and state tax base and revenue would be expected.

D. Agricultural or Industrial Production

The permit modification would occur within an existing refinery that is located in an industrial/commercial area. The amount of allowable emissions increases from an existing and operating refinery would not be expected to significantly affect agricultural or industrial production.

Given the long history of operations at this facility and the magnitude of this project, and the limited amount of emissions increases which would be allowable under permit requirements, significant impacts would not be expected as a result of project approval.

E. Human Health

MAQP #2161-30 would incorporate conditions to ensure that the proposed permit modification would be operated in compliance with all applicable air quality rules and standards. These rules and standards are designed to be protective of human health. As described in Section 8.F of this EA, any additional emissions that would result would be minimized by conditions in MAQP #2161-30. Therefore, only minor impacts would be expected on human health from the proposed project.

Given the long history of operations at this facility and the magnitude of this project, and the limited amount of emissions increases which would be allowable under permit requirements, significant impacts would not be expected as a result of project approval.

F. Access to and Quality of Recreational and Wilderness Activities

This project would have minor additional impacts on recreational or wilderness activities because the expansion project would be constructed within an existing facility. The Calumet refinery (as well as the proposed expansion) is adjacent to the Rivers Edge Trail. In 1998, a project was completed to upgrade a major sewer line at the north end of the 9th Street bridge which included a total rebuild of the trail south of the refinery complete with a trail underpass of Ninth Street North, and a tunnel behind the bulkhead of the abandoned 10th Street Bridge to establish formal public use and access. Additionally, Calumet has a use agreement with the City of Great Falls "for the purpose of installing, operating and maintaining a boat ramp solely for the purpose of emergency access to the Missouri River." The City of Great Falls also granted Calumet access to the River's Edge Trail at certain times for training purposes or in the event of an emergency. However, because Calumet is an existing facility, proposing to expand at the existing location, the project would not be expected to result in significant changes in access to and quality of recreational and wilderness activities.

G. Quantity and Distribution of Employment

Given the long history of operations at this facility and the magnitude of this project, no more than minor impacts would be expected as a result of project approval.

H. Distribution of Population

Given the long history of operations at this facility and the magnitude of this project, no more than minor impacts would be expected as a result of project approval.

I. Demands of Government Services

Government services would be required for acquiring the appropriate permits for the proposed project and verifying compliance with the permits that would be issued. However, because this is an existing facility, the Department would not anticipate a major increase in the level of government services that would be provided. Therefore, the Department believes that the demands for government services would not be significant.

J. Industrial and Commercial Activity

Given the long history of operations at this facility and the magnitude of this specific project, significant impacts would not be expected as a result of project approval.

K. Locally Adopted Environmental Plans and Goals

Calumet has held public open house meetings to discuss the original project. State and local officials were also available to discuss the project and answer any questions associated with the refinery's expansion project. MAQP #2161-30 is revisiting the action approved in MAQP #2161-29. MAQP #2161-30 would contain limits for protecting air quality and to keep facility emissions in compliance with any applicable ambient air quality standards, which would be consistent with any locally adopted environmental plan or goal for operating at this proposed site.

Given the long history of operations at this facility and the magnitude of this project, and the limited amount of emissions increases which would be allowable under permit requirements, significant impacts would not be expected as a result of project approval.

L. Cumulative and Secondary Impacts

Given the long history of operations at this facility and the magnitude of this project, and the limited amount of emissions increases which would be allowable under permit requirements, significant impacts would not be expected as a result of project approval.

Recommendation: An Environmental Impact Statement (EIS) is not required.

If an EIS is not required, explain why the EA is an appropriate level of analysis: All potential effects resulting from construction and operation of the proposed facility are negligible or minor; therefore, an EIS is not required.

Other groups or agencies contacted or which may have overlapping jurisdiction: Montana Department of Environmental Quality - Permitting and Compliance Division (Industrial and Energy Minerals Bureau); Montana Natural Heritage Program; and the State Historic Preservation Office (Montana Historical Society).

Individuals or groups contributing to this EA: Montana Department of Environmental Quality (Air Resources Management Bureau), Montana State Historic Preservation Office (Montana Historical Society).

EA prepared by: Shawn Juers
Date: 9/26/2017