



July 9, 2020

CHS Inc.
Laurel Refinery
P.O. Box 909
Laurel, MT 59044-0909

Dear Ms. Kennah:

Montana Air Quality Permit #1821-43 is deemed final as of July 9, 2020, by the Department of Environmental Quality (Department). All conditions of the Department's Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

Conditions: See attached.

A handwritten signature in black ink that reads "Julie A. Merkel". The signature is written in a cursive style.

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

A handwritten signature in black ink that reads "Craig Henrikson". The signature is written in a cursive style.

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

JM:CH
Enclosure

Montana Department of Environmental Quality
Air, Energy & Mining Division

Montana Air Quality Permit #1821-43

CHS Inc.
Laurel Refinery
P.O. Box 909
Laurel, MT 59044-0909

July 9, 2020



MONTANA AIR QUALITY PERMIT

Issued to: CHS Inc.	MAQP: #1821-43
Laurel Refinery	Application Complete: 4/13/2020
P.O. Box 909	Preliminary Determination (PD) Issued: 5/18/2020
Laurel, MT 59044-0909	Department Decision (DD) Issued: 6/23/2020
	Appeal Period Ends: July 23, 2020
	Permit Final: 7/9/2020

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to CHS Inc. (CHS) pursuant to Sections 75-2-204, 211, 213, and 215, 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/Description

CHS operates the Laurel petroleum refinery, located in the South ½ of Section 16, Township 2 South, Range 24 East, in Yellowstone County, Montana. The facility includes, but is not limited to, the permitted equipment described in the following sections:

- Refinery Limitations and Conditions associated with MAQP #1821-05 (Section II)
- Fuel Gas Combustion Devices (Section III)
- Mild Hydrocracker with associated Zone D sulfur recovery unit (SRU) and tail gas treatment unit (TGTU) (Section IV)
- Boiler #10 (Section V)
- Truck Loading Rack and Vapor Combustion Unit (VCU) (Section VI)
- No. 1 Crude Unit (Section VII)
- Ultra-Low Sulfur Diesel (ULSD) Unit and Hydrogen Plant (Section VIII)
- TGTU for Zone A's SRU #1 and SRU #2 trains (Section IX)
- Fluidized Catalytic Cracking Unit (FCCU) (Section X)
- Naphtha Hydrotreater (NHT) Unit, Delayed Coker Unit, and Zone E SRU/TGTU and Tail Gas Incinerator (TGI) (Section XI)
- Boiler #11 (Section XII)
- Railcar Light Product Loading Rack and VCU and Railcar Gasoline Component Unloading (Section XIII)

- Boiler #12 (Section XIV)
- Benzene Reduction Unit (Section XV)
- Product Storage Tanks (Section XVI)
- Product Storage Tank 133 (Section XVII)
- Wastewater Facilities (Section XVIII)
- Intermediate Storage Tanks 146 and 147 (Section XIX)
- Replacement Refinery Flare / Waste Gas Control System (Section XX)
- Sour Water Stripper Ammonia Combustor (Section XXI)
- Crude Blending Project (Section XXII)
- Hydrogen Plant #3 Project (Section XXIII)
- Asphalt Storage Tanks (Section XXIV)
- Multi-Unit Expansion Project (Section XXV)
- General Conditions (Section XXVI)

B. Current Permit Action

On March 9, 2020, the Department received an application from CHS for modification of MAQP #1821-42. An application incompleteness letter was issued to CHS on April 3, 2020, requesting additional information. A response was received from CHS by the Department on April 13, 2020. The requested change proposes to modify the MAQP to provide a refinery expansion which is identified as the Multi-Unit Expansion (MUE) Project. The MUE project includes projects within the #2 Crude Unit (#2 CU), Mild Hydrocracker (MHC), Delayed Coker (DCU), and Naphtha Hydrotreater (NHT). The #2 CU will be modified to increase its capacity and to provide additional crude processing flexibility. The atmospheric distillation column within the #2 CU will be replaced, an existing process heater will be replaced, and the stack of another existing heater will be relocated. The MHC will be modified to increase its capacity. The three MHC reactors, H₂S stripper and high pressure absorber will be replaced with higher capacity equipment and a naphtha stabilizer will be added to the unit. The DCU will be modified to increase its capacity. A second Coker Charge Heater (H-7502) will be installed. Modifications to the NHT and associated support facilities will be made to improve management of unit feed and handling of heavier hydrocarbon gases (i.e., propane, butane, etc.). The project also involves replacing existing natural gas-fired Boiler 9 with a higher capacity boiler (Boiler 13). Boiler 13 will be fired with refinery fuel gas (RFG).

Unrelated MAQP updates not associated with the MUE project included a review of the current NO_x limits on existing Boilers #11 and #12, and a revised BACT analysis to update these limits. This request is related to the original NO_x limits which were established in 2006 for Boiler #11, and in 2008 for Boiler #12.

Several minor administrative clarifications were also incorporated into the MAQP including reporting requirements and making sure MAQP conditions reflect planned language to be included in the CHS Title V Operating Permit renewal which is currently being updated. Administrative changes include moving to electronic submittal of reports to eliminate duplicate hardcopy submittals. The application also addressed plans for a new stack on the #2 CU Main Heater which is necessary as a result of the new #2 CU Vacuum Heater and provides for a single stack to replace the split stack on the NHT Charge Heater. The stack testing on the NHT Charge Heater will be improved with the addition of a single stack. Both of the emitting units associated with these stack changes will not see a change in potential to emit as they are limited by their burner design capacity and any change in pressure drop in the exhaust stacks does not change their potential to emit. The application also requested a review of source test stack testing frequencies and an analysis of limits including those with CEMS. Minor changes to stack testing frequencies was completed where appropriate. The MUE project planned schedule associated with the MAQP application represents a multi-year effort and is planned to be completed in various phases which will be coordinated with regularly scheduled maintenance turnarounds starting in August 2020, and currently planned to be completed in 2024.

Section II: Refinery Limitations and Conditions associated with MAQP #1821-05

With the issuance of MAQP #1821-05, CHS requested to place enforceable limits on future site-wide emissions for the collective units that were in operation at the facility. Although modifications (including removal and addition of various emitting units) have occurred at the facility since these limitations were put in place, the following units identified at the time of issuance of MAQP #1821-05 continue to be subject to the limitations and conditions within this Section:

1. Gas-fired external combustion source type, includes:
 - a. #1 Crude heater
 - b. Crude Preheater
 - c. #1 Crude Vacuum Heater
 - d. #2 Crude Heater
 - e. #2 Crude Vacuum Heater
 - f. Alkylation Unit Hot Oil Belt Heater
 - g. Platformer Heater (P-HTR-1)
 - h. Platformer Debutanizer Heater

- i. FCC Feed Preheater (this heater was shut down as part of the MHC project MAQP 1821-23). A replacement heater has been permitted and constructed but is not included as part of these site-wide limits
- j. #1 Naphtha Unifiner charge heater (renamed NHT Reboiler Heater #2 – H-8303 for new service as part of coker project in 1821-13)
- k. #2 NU heater (shutdown as part of coker project – MAQP 1821-09)
- l. MDU Charge Heater (H-8301) (Shutdown as part of ULSD project = MAQP 1821-09) [Now not part of PAL]
- m. MDU Stripper Heater (Shutdown as part of ULSD project – MAQP 1821-09)
- n. PDA Heater (shutdown as part of coker project, MAQP #1821-13)
- o. #1 Road Oil/Asphalt Loading heater (asphalt loading heater #1)
- p. #2 road oil heater (removed from service and now not part of the PAL)
- q. BP2 Heater (the heater has been removed but the BP2 tank is still present)
- r. 60 Tank Heater
- s. #1 Fuel Can Heater (#1 fuel oil heater)
- t. #3 Boiler (permanently shut down as Consent Decree project; MAQP #1821-15. Has been removed.)
- u. #4 Boiler (permanently shut down as Consent Decree project; MAQP 1821-22. Has been removed.)
- v. #5 Boiler (permanently shut down as Consent Decree project; MAQP 1821-22. Has been removed.)
- w. #9 Boiler (Planned to be shutdown with implementation of the MUE Project)
- x. CO Boiler (permanently shut down as Consent Decree project; MAQP 1821-15. Has been removed.)
- y. #10 Boiler
- z. H-101 Zone D Hydrogen Plant Reformer Heater
- aa. H-201 Reactor Charge Heater
- bb. H-202 Fractionator Feed Heater

- cc. C-201B (Permanently shut down and replaced with electric)
 - dd. NU Splitter Heater (renamed NHT Splitter Reboiler H-8304, MAQP #1821-13)
 - ee. #1 NU Stripper Heater (renamed NHT Reboiler Heater #1 H-8302, MAQP #1821-13)
2. Fuel oil-fired external combustion sources, includes:
 - a. #3 Boiler (permanently shut down as Consent Decree Project; MAQP #1821-15. Has been removed.)
 - b. #4 Boiler (permanently shut down as Consent Decree Project; MAQP #1821-22. Has been removed.)
 - c. #5 Boiler (permanently shut down as Consent Decree Project: MAQP #1821-22. Has been removed.)
 - d. #1 crude heater (ceased burning oil)
 3. Gas-fired internal combustion source, includes:
 - a. Platformer recycle turbine (permanently shut down in 2018)
 - b. #1-4 unifier compressors (shutdown with ULSD and coker projects)
 4. FCC unit (FCCU) Regenerator
 5. Zone A Sulfur Recovery Unit (SRU) Tail Gas Incinerator (TGI, SRU-AUX-4)
 6. Zone D SRU Incinerator
 7. Fugitive equipment leaks include all equipment, as defined in 40 Code of Federal Regulations (CFR) 60, Subpart VV, in hydrocarbon service
 8. Wastewater sewers, separation, and treatment facilities
 9. Cooling tower sources: #1 cooling tower (CT), #2 CT, #3 CT, #5 CT;
 10. Loading facilities:
 - a. light product truck rack and vapor combustion unit (VCU) [excludes new facility permitted with 1821-27]
 - b. heavy oil truck rack, and
 - c. heavy oil rail rack.

11. Storage tanks: Tank numbers 2, 6 (demo'd), 7, 9 (Replaced with Tank 127), 12, 28 (Replaced with Tank 126), 41, 47, 56, 60, 61, 62, 63, 64 (demo'd), 65 (Replaced with Tank 144), 66, 67 (Replaced with Tank 145), 68, 70, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 85, 86, 88, 91, 92, 93, 94, 95, 96, 100, 101, 102, 103, 104, 108, 109, 110, 111, 112, 113, 114, 117, 118, 120, 121, 122, 123, B-1, B-2, B-7, BP-2, firetk 2, firetk 3, and firetk 4.

A. National Emission Standards for Hazardous Air Pollutants

CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements as required by 40 CFR 61, Subpart FF- National Emissions Standards for Benzene Waste Operations (ARM 17.8.341 and 40 CFR 61, Subpart FF).

B. Annual Emission Limitations (ARM 17.8.749):

1. SO₂ emissions shall not exceed 2,980.3 tons per year (TPY)
2. NO_x emissions shall not exceed 999.4 TPY
3. CO emissions shall not exceed 678.2 TPY
4. Volatile organic compounds (VOC) emissions shall not exceed 1,967.5 TPY
5. Particulate matter with an aerodynamic diameter of 10 microns or less (PM₁₀) emissions shall not exceed 152.2 TPY
6. Particulate matter (PM) emissions shall not exceed 162.2 TPY

C. Compliance Determination (ARM 17.8.749):

CHS shall determine the CO, NO_x, and VOC emissions for combustion sources by utilizing the Plant Information (PI) system information and normalize that PI system information to the refinery yield report. CHS shall also provide the Department with the amount of fuel consumed annually in the refinery as documented in the refinery yield report. This methodology was used to determine the CO, NO_x, and VOC emissions in CHS's MAQP #1821-05 application and again in the August 12, 2004, letter from CHS to the Department.

CHS will track compliance with the emission caps based on source type, pollutant, calculation basis (emission factors, estimated yield and conversion), and key parameters (fuel oil use, fuel gas use, process gas use, and CEMS data). The units included in each source type are listed in Section I.A of the permit analysis. The calculation basis for each unit is listed in Attachment A (Refinery Limitations and Conditions associated with MAQP #1821-05 Compliance Determination).

The annual emission limitations were established using specific calculation methods for each source. If an improved calculation methodology is identified and approved by the Department, the emission limitation for that pollutant(s) shall be reviewed and updated, if needed, before the new calculation method is utilized.

D. Reporting and Recordkeeping Requirements (ARM 17.8.749):

CHS shall provide quarterly electronic emission reports to demonstrate compliance with Section II.B using data required in Section II.C. The quarterly report shall also include CEMS monitoring downtime that occurred during the reporting period.

E. Testing Requirements

1. Fuel flow rates, fuel heating value, production information and other data, as needed, shall be recorded during the performance of source tests in order to develop emission factors for use in the compliance determinations (ARM 17.8.749).
2. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).
3. The Department may require further testing (ARM 17.8.105).

F. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749):

1. CHS 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 as 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. All records compiled in accordance with this permit must be maintained by CHS 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, EPA, and the Yellowstone County Air Pollution Control Agency, and must be submitted to the Department upon request (ARM 17.8.749).
3. CHS 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 the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

G. Notification Requirements

CHS shall provide the Department with written notification of the following dates within the following time periods (ARM 17.8.749 and 340):

1. All compliance source tests as required by the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).
2. The Department must be notified promptly by telephone or email 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 (ARM 17.8.110).

Section III: Limitations and Conditions for Fuel Gas Combustion Devices

A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS). The following subparts, at a minimum, are applicable:

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
2. Subpart J - Standards of Performance for Petroleum Refineries applies to all fuel gas combustion devices with the exception to those subject to NSPS Subpart Ja. Applicability of NSPS Subpart Ja to fuel gas combustion devices is identified on a source by source basis within the permit.
3. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.

B. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 (2)).

C. Limitations on Fuel Gas Devices

1. For fuel gas combustion devices where construction, reconstruction, or modification commenced prior to May 14, 2007, refinery fuel gas burned in fuel combustion devices shall not exceed 0.10 grains of H₂S per dry standard cubic foot (162 parts per million, volumetric dry (ppm_{vd}) H₂S) per rolling 3-hour average. This does not apply to the Sour Water Stripper Ammonia Combustor (ARM 17.8.340, ARM 17.8.749, 40 CFR 60, Subpart J).
2. Refinery fuel gas burned in fuel combustion devices shall not exceed 0.05 grains of H₂S per dry standard cubic foot (81 ppm_{vd} H₂S) per 12-month average (ARM 17.8.340 and ARM 17.8.749).

3. For fuel gas combustion devices where construction, reconstruction, or modification commenced after May 14, 2007, CHS shall not burn any fuel gas that contains H₂S in excess of 162 ppm_{vd} determined hourly on a 3-hour rolling average basis and H₂S in excess of 60 ppm_{vd} determined daily on a 365-successive calendar day rolling average basis. This does not apply to the Sour Water Stripper Ammonia Combustor (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Ja).

D. Monitoring Requirements

1. CHS shall install and operate the following Continuous Emissions Monitoring System (CEMS) / Continuous Emission Rate Monitor System (CERMS): Continuous concentration (dry basis) monitoring of H₂S in refinery fuel gas burned in all refinery fuel gas combustion devices. This does not apply to the Sour Water Stripper Ammonia Combustor.
2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subpart J, 60.100-108, Subpart Ja, 60.100a-108a and Appendix B, Performance Specification 7 and Appendix F (Quality Assurance/Quality Control) provisions.
3. H₂S refinery fuel gas CEMS and fuel gas flow rate meters shall comply with all applicable requirements of the Billings/Laurel SO₂ State Implementation Plan (SIP) Emission Control Plan, including Exhibit A and Attachments, adopted by the Board of Environmental Review, June 12, 1998, and stipulated to by Cenex Harvest States Cooperative and its successor CHS.
4. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.

E. Compliance Determinations

1. Compliance determinations for SO₂ and H₂S limits for the fuel gas-fired units within the refinery shall be based upon CEMs data utilized for H₂S, as required in Section III.D.1 and fuel firing rates, if these units are fired on refinery fuel gas. Firing these units solely on natural gas shall demonstrate compliance with the applicable SO₂ limits. This does not apply to the Sour Water Stripper Ammonia Combustor.
2. In addition to the testing required in each section, compliance determinations for the emission limits applicable to the fuel gas shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test, and/or available CEM data. Fuel flow rates, fuel heating value, production information and other data, as needed, shall be recorded for each emitting unit during the performance of the source tests in order to develop emission factors for use in the compliance determinations. New emission factors (subject to review and approval by the Department)

shall become effective within 60 days after the completion of a source test. Firing these units solely on natural gas shall demonstrate compliance with the applicable VOC limits (ARM 17.8.749).

F. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

CHS shall submit quarterly emission reports within 30 days of the end of each calendar quarter. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service).

The quarterly report shall also include the following:

1. Source or unit operating time during the reporting period and 24-hour (daily) average concentration of H₂S in the refinery fuel gas burned at the permitted facilities.
2. Monitoring downtime that occurred during the reporting period.
3. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section III.C.
4. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section III.C. (ARM 17.8.749).
5. Reasons for any emissions in excess of those specifically allowed in Section III.C. with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

Section IV: Limitations and Conditions for the Mild Hydrocracker

A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable:

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
2. Subpart J - Standards of Performance for Petroleum Refineries applies to the Fractionator Feed Heater Stack (H-202), the Reactor Charge Heater Stack (H-201), and the Hydrogen Reformer Heater (H-101).
3. Subpart Ja - Standards of Performance for Petroleum Refineries applies to the Hydrogen Reformer Heater (H-102) and SRU Incinerator Stack (INC-401).
4. Subpart GGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, applies to the Mild Hydrocracker Unit.

5. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the Mild Hydrocracker unit.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):
 1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 2. Subpart CC - Refinery MACT I shall apply to, but not be limited to, affected sources or the collection of emission points as defined in this subpart.
 - C. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 (2)).
 - D. Limitations on Individual Sources
 1. Zone D SRU Incinerator Stack (INC-401)
 - a. CHS shall operate and maintain the TGTU on the Zone D SRU to limit SO₂ emissions from the Zone D SRU incinerator stack (INC-401) by following the below requirements:
 - i. CHS shall not exceed 53.17 tons/rolling 12-calendar month total, applicable at all times except malfunction (ARM 17.8.749).
 - ii. CHS shall not exceed 14.21 lb/hr (ARM 17.8.749).
 - iii. CHS shall not exceed 250 parts per million, volumetric dry (ppm_{vd}), rolling 12-hour average corrected to 0% oxygen, except during periods of startup, shutdown, and malfunction (ARM 17.8.752).
 - iv. CHS shall minimize the frequency and duration of startups and shutdowns of the Zone D SRP by operating at all times in accordance with an operation, maintenance and monitoring plan meeting the requirements of 40 CFR 63.1574(f) (ARM 17.8.752).
 - v. CHS shall comply with 40 CFR 63 subpart UUU (Refinery MACT II) operating limits at 63.1568(a)(4) during periods of startup and shutdown (ARM 17.8.752).

- vi. For the purposes of startup and shutdown, startup process begins when the Zone D SRU Combustion Air Blower is started up and ends when the use of purge gas (steam, nitrogen or natural gas) is terminated. Shutdown process begins when purge gas is initiated and ends when the Zone D SRU Combustion Air Blower is shut down. CHS shall document these events to define periods of startup and shutdown for the purpose of compliance demonstration (ARM 17.8.749).
- b. NO_x emissions from the Zone D SRU incinerator stack shall not exceed (ARM 17.8.749):
 - i. 3.5 tons/rolling 12-calendar month total,
 - ii. 19.2 lb/day, and
 - iii. 0.8 lb/hr.
- c. CHS shall not fire fuel oil in this unit (ARM 17.8.749).

2. Reformer Heater Stack (H-101)

- a. SO₂ emissions from H-101 shall not exceed (ARM 17.8.749):
 - i. 1.68 tons/rolling 12-calendar month total
 - ii. 2.15 lb/hr
- b. NO_x emissions from H-101 shall not exceed (ARM 17.8.749):
 - i. 27.16 tons/rolling 12-calendar month total
 - ii. 6.78 lb/hr
- c. CO emissions from H-101 shall not exceed (ARM 17.8.749):
 - i. 13.93 tons/rolling 12-calendar month total
 - ii. 4.51 lb/hr
- d. VOC emissions from H-101 shall not exceed 0.35 tons/rolling 12-calendar month total (ARM 17.8.749).
- e. CHS shall not combust fuel oil in this unit (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60, Subpart J).

3. Reformer Heater Stack (H-102)

- a. All available 100 Unit PSA tailgas shall be fired in the 100 Unit Hydrogen Plant reformer heaters, except during periods of startup, shutdown or process upset (ARM 17.8.752).

- b. CHS shall not burn in the H-102 Reformer Heater any fuel gas that contains H₂S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60, Subpart Ja).
- c. NO_x emissions from H-102 shall not exceed:
 - i. 40 ppmv (dry basis, corrected to 0 percent excess air) on a 30-day rolling average basis (40 CFR 60, Subpart Ja)
 - ii. 3.02 lb/hr (24-hr rolling average) (ARM 17.8.752)
 - iii. 11.3 tons/rolling 12-calendar month total (ARM 17.8.749)
- d. CO emissions from H-102 shall not exceed:
 - i. 5.7 lb/hr (ARM 17.8.752)
 - ii. 25.1 tons/rolling 12-calendar month total (ARM 17.8.749)
- e. H-102 shall be fitted with Ultra Low NO_x Burners (ULNBs) (ARM 17.8.752).
- f. CHS shall implement proper design and good combustion techniques to minimize CO, VOC, and PM/PM₁₀/PM_{2.5} emissions (ARM 17.8.752).

4. Reactor Charge Heater Stack (H-201)

- a. SO₂ emissions from H-201 shall not exceed (ARM 17.8.749):
 - i. 4.35 tons/rolling 12-calendar month total
 - ii. 1.99 lb/hr
- b. NO_x emissions from H-201 shall not exceed (ARM 17.8.749):
 - i. 11.56 tons/rolling 12-calendar month total
 - ii. 2.90 lb/hr
- c. CO emissions from H-201 shall not exceed (ARM 17.8.749):
 - i. 8.92 tons/rolling 12-calendar month total
 - ii. 2.23 lb/hr
- d. VOC Emissions from H-201 shall not exceed 0.91 tons/rolling 12-calendar month total (ARM 17.8.749).
- e. CHS shall not fire fuel oil in this unit (ARM 17.8.749).

5. Fractionator Feed Heater Stack (H-202)
 - a. SO₂ emissions from H-202 shall not exceed (ARM 17.8.749):
 - i. 3.14 tons/rolling 12 calendar-month total
 - ii. 1.43 lb/hr
 - b. NO_x emissions from H-202 shall not exceed (ARM 17.8.749):
 - i. 8.34 tons/rolling 12 calendar-month total
 - ii. 2.09 lb/hr
 - c. CO emissions from H-202 shall not exceed (ARM 17.8.749):
 - i. 6.43 tons/rolling 12-calendar month total
 - ii. 1.61 lb/hr
 - d. VOC emissions from H-202 shall not exceed 0.65 tons/rolling 12-calendar month total (ARM 17.8.749).
 - e. CHS shall not fire fuel oil in this unit (ARM 17.8.749).

E. Monitoring Requirements

1. CHS shall install and operate the following CEMS/CERMS for the SRU Incinerator Stack (INC-401):
 - a. SO₂ (SO₂ SIP, 40 CFR 60 Subpart Ja)
 - b. O₂ (40 CFR 60, Subpart Ja)
 - c. Volumetric Flow Rate (SO₂ SIP)
2. CHS shall install, operate, calibrate, and maintain the following CEMS/CERMS for H-102 Reformer Heater Stack (H-102):
 - a. NO_x (40 CFR 60, Subpart Ja)
 - b. O₂ (40 CFR 60, Subpart Ja)
 - c. Stack Flow Rate (ARM 17.8.749)
3. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts J, 60.100-108, Subparts Ja, 60.100a-60.108a, and Appendix B, Performance Specifications 2, 3, 6, and Appendix F; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors (ARM 17.8.749).

4. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, and breakdowns and repairs of CEMS related equipment. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated (ARM 17.8.749).

F. Testing Requirements

1. The SRU Incinerator Stack (INC-401) shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department for SO₂ and shall be tested on an every 6-year basis, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x. The results submitted to the Department in order to demonstrate compliance with the SO₂ and NO_x emission limits contained in Section IV.C.1.a, b, and c (ARM 17.8.105 and ARM 17.8.749).
2. The Reformer Heater Stack (H-101) shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section IV.C.2.b and c (ARM 17.8.105 and ARM 17.8.749).
3. The Reformer Heater Stack (H-102) shall be tested every three years from the date of the last source test, in conjunction with annual CEMS/CERMS RATA performance testing in accordance with Appendix F (40 CFR Part 60) requirements, or according to another testing/ monitoring schedule as may be approved by the Department, for NO_x/O₂ and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section IV.C.3.c and d (ARM 17.8.105 and ARM 17.8.749, 40 CFR 60, Subpart Ja).
4. The Reactor Charge Heater Stack (H-201) shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section IV.C.4.b and c (ARM 17.8.105 and ARM 17.8.749).
5. The Fractionator Feed Heater Stack (H-202) shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section IV.C.5.b and c (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations

1. In addition to the testing required in Section IV.E, compliance determinations for hourly, 24-hour, and annual SO₂ limits for the SRU Incinerator stack shall be based upon CEMS data utilized for SO₂ as required in Section IV.D.1.
2. Compliance with the opacity limitation listed in Section IV.C shall be determined using EPA Reference Method 9 testing by a qualified observer.

H. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

CHS shall submit quarterly emission reports within 30 days of the end of each calendar quarter to the Department based on data from the installed CEMS/CERMS. Emission reporting for SO₂ from the emission rate monitor shall consist of a daily 24-hour average (ppm SO₂, corrected to 0% oxygen (O₂)) and a 24-hour total (lb/day) for each calendar day. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or uploaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service). The quarterly report shall also include the following:

1. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates.
2. Monitoring downtime that occurred during the reporting period.
3. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Sections IV.C.1 through 5.
4. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Sections IV.C.1 through 5 (ARM 17.8.749).
5. Reasons for any emissions in excess of those specifically allowed in Sections IV.C.1 through 5 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

Section V: Limitations and Conditions for Boiler #10

A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60 for Boiler #10. The following subparts, at a minimum, are applicable (ARM 17.8.340):

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
2. Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.
3. Subpart J - Standards of Performance for Petroleum Refineries. The requirements of this Subpart apply to Boiler #10.

4. Subpart GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the refinery fuel gas supply lines to Boiler #10.

B. Emission Limitations for Boiler #10

1. Fuel oil burning is not allowed in this unit (ARM 17.8.340, ARM 17.8.749, and ARM 17.8.752).
2. SO₂ emissions shall not exceed:
 - a. 60 ppmv H₂S in refinery fuel gas, 365-day rolling average (ARM 17.8.752)
 - b. 4.14 tons/rolling 12-calendar month total (ARM 17.8.749)
 - c. 2.53 lb/hr (ARM 17.8.752)
3. NO_x emissions shall not exceed:
 - a. 0.03 pounds per million British thermal units – Higher Heating Value (lb/MMBtu-HHV), 365-day rolling average (ARM 17.8.752)
 - b. 13.13 tons/rolling 12-calendar month total (ARM 17.8.749)
 - c. 3.5 lb/hr (ARM 17.8.749)
4. During periods of startup or shutdown, CO emissions shall not exceed 10.0 lb/hr, 24-hour rolling average (ARM 17.8.752). Otherwise, CO emissions shall not exceed:
 - a. 0.05 lb/MMBtu-HHV, 365-day rolling average (ARM 17.8.752)
 - b. 21.88 tons/rolling 12-calendar month total (ARM 17.8.749)
 - c. 5.0 lb/hr (ARM 17.8.749)
5. VOC emissions shall not exceed 2.24 tons/rolling 12-calendar month total (ARM 17.8.752).
6. Opacity shall not exceed 20%, averaged over any 6 consecutive minutes (ARM 17.8.304).
7. Boiler #10 shall be fitted with ULNBs, flue gas recirculation (FGR) and steam injection to the flame zone (ARM 17.8.752), and have a minimum stack height of 75 feet above ground level (ARM 17.8.749).

C. Monitoring Requirements

1. CHS shall install, operate, and maintain a CEMS/CERMS on Boiler #10, to monitor and record the NO_x and O₂ for demonstration of compliance with the limits in Sections V.B, for each day when the boiler is combusting fuel gas (40 CFR 60, Subpart Db).

2. Boiler #10's continuous NO_x and O₂ concentration monitors shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts Db, Appendix B (Performance Specifications 2 and 3), and Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.340, ARM 17.8.105 and ARM 17.8.749).
3. CHS shall install, operate, and maintain a CEMS/CERMS on Boiler #10, to monitor and record the CO for demonstration of compliance with the limits in V.B, for each day when the boiler is combusting fuel gas. The CO CEMS shall comply with all applicable provisions of 40 CFR 60, Appendix B (Performance Specification 4) and Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.749).
4. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated (ARM 17.8.749).
5. CHS shall install and operate a volumetric stack flow rate monitor on Boiler #10. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1 (ARM 17.8.749).

D. Testing Requirements

Boiler #10 shall be tested for NO_x and CO, concurrently at a minimum of every 5 years or according to another testing/monitoring schedule as may be approved by the Department. Boiler #10 shall be tested for VOC as requested by the Department. Testing shall be conducted for both natural gas and refinery fuel gas (ARM 17.8.105 and ARM 17.8.106).

E. Compliance Determinations

1. Compliance with the opacity limitations shall be determined according to 40 CFR, Part 60, Appendix A, Method 9 Visual Determination of Opacity of Emissions from Stationary Sources (ARM 17.8.749).
2. With exception to the initial performance test period, compliance with the lb/MMBtu limit(s) will be demonstrated using statistically significant F-factor values. The factor will be updated on a regular basis using data from all valid fuel gas samples representative of the fuel gas burned in Boiler #10. The method of compliance demonstration involving F-factor statistical significance is subject to change upon agreement with the Department and CHS (40 CFR 60, Appendix A, Reference Method 19).
3. Compliance with the NO_x lb/hr limit shall be determined using the NO_x CEM and the volumetric stack flow rate monitor (ARM 17.8.749).

4. Compliance with the CO lb/hr limit in Section V.B shall be determined using the CO CEM and the volumetric stack flow rate monitor (ARM 17.8.749).

F. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

1. CHS shall submit quarterly electronic emission reports to the Department within 30 days of the end of each calendar quarter. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service). Reporting requirements shall be consistent with 40 CFR Part 60, or as specified by the Department (ARM 17.8.340). The quarterly report shall include the following:
 - a. SO₂ emission data from the refinery fuel gas system continuous H₂S concentration monitor required by Section III. The SO₂ emission rates shall be reported for the following averaging periods:
 - i. Average lb/hr per calendar day
 - ii. Total lb per calendar day
 - iii. Total tons per month
 - b. NO_x emission data from the CEMS, fuel gas flow rate meter, and emission factors developed from the most recent compliance source test. The NO_x emission rates shall be reported for the following averaging periods:
 - i. Average lb/MMBtu per calendar day
 - ii. Total tons per month
 - iii. lb/MMBtu per rolling 30-day average
 - iv. lb/MMBtu per rolling 365-day average
 - v. Daily average and maximum lb/hr
 - c. Source or unit operating time during the reporting period and daily, monthly, and quarterly refinery fuel gas and natural gas consumption rates.
 - d. Monitoring downtime that occurred during the reporting period.
 - e. An excess emission summary, which shall include excess emissions (lb/hr) for each pollutant identified in Section V.B.
 - f. Reasons for any emissions in excess of those specifically allowed in Section V.B with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

2. CHS shall comply with the reporting and recordkeeping requirements in 40 CFR 60.7 and 40 CFR 60.49b.

Section VI: Limitations and Conditions for the Truck Loading Rack and associated VCU

- A. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements of ARM 17.8.342, as specified in 40 CFR Part 63, NESHAP for Source Categories.
 1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 2. Subpart CC - National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries.
 3. The product loading rack and vapor combustion unit shall be operated and maintained as follows:
 - a. CHS's product 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 and ARM 17.8.752).
 - b. CHS's collected vapors shall be routed to the VCU at all times. In the event the VCU is inoperable, CHS 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 17.8.749).
 - 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).
 - 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 rack from passing to another loading rack (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. CHS 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 product loading rack.

- ii. CHS shall require the cargo tank identification number to be recorded as each gasoline cargo tank is loaded at the terminal.
 - iii. CHS 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. CHS shall notify the owner or operator of each non-vapor-tight cargo tank loaded at the product loading rack within 3 weeks after the loading has occurred.
 - v. CHS shall take the necessary steps to ensure that any non-vapor-tight cargo tank will not be reloaded at the product loading rack until vapor tightness documentation for that cargo tank is obtained, which documents that:
 - aa. The gasoline cargo tank meets the applicable test requirements in 40 CFR 63.425(e) to this permit.
 - bb. 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 pass the annual certification test described in 40 CFR 63.425(e).
 - g. CHS shall ensure that loadings of gasoline cargo tanks at the product 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. CHS shall ensure that the terminal's and the cargo tank's vapor recovery systems are connected during each loading of a gasoline cargo tank at the product loading rack (ARM 17.8.342).
 - i. The stack for the truck loading rack shall be at least 40 feet above grade (ARM 17.8.749).
- B. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements, as specified in 40 CFR Part 60, NSPS for Stationary Sources. The following subparts, at a minimum, are applicable (ARM 17.8.340):
 - 1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.
3. Subpart XX - Standards of Performance for Bulk Gasoline Terminals.

C. Emission Limitations

1. The total annual VOC emissions from the truck loading rack, VCU and associated equipment (which includes all associated storage tanks (135-139, 142, 143 and Additive Tanks # 1-4)), and any fugitives shall not exceed 39.23 TPY based on a rolling 12-calendar month total. This is total combined VOC emission limit for the applicable units listed in this Section (VI) and Section XVI (ARM 17.8.749).
2. VCU Emission Limitations
 - a. The total VOC emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 milligrams per liter (mg/L) of gasoline loaded (ARM 17.8.342, 40 CFR 63, Subpart CC, 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, testing as requested by the Department (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, testing as requested by the Department (ARM 17.8.752).
 - d. CHS shall not cause or authorize to be discharged into the atmosphere from the enclosed VCU any visible emissions that exhibit an opacity of 20% or greater over any 6 consecutive minutes (ARM 17.8.304(2)).

D. Monitoring Requirements

1. CHS shall perform the testing and monitoring procedures specified in 40 CFR §§63.425 and 63.427 of Subpart R, except §63.425(d) or §63.427(c) (ARM 17.8.342).
2. CHS shall install and operate a continuous parameter monitoring system capable of measuring temperature in the firebox or in the ductwork immediately downstream from the firebox in a position before any substantial heat exchange occurs (ARM 17.8.342 and 40 CFR 63, Subpart CC).
3. CHS 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 Parts 60.482-1 through 60.482-10 (ARM 17.8.340).

4. A monitoring and maintenance program, as described under 40 CFR 60, Subpart VVa, and meeting the requirements of 40 CFR 60, Subpart GGGa shall be instituted (ARM 17.8.749).

E. Testing Requirements

1. CHS shall comply with all test methods and procedures as specified by Subpart R §63.425 (a) through (c), and §63.425 (e) through (h). This shall apply to, but not be limited to, the product loading rack, the vapor processing system, and all gasoline equipment located at the product loading rack.
2. The product loading rack VCU shall be tested for VOCs, and compliance demonstrated with the emission limitation contained in Section VI.C.1 and C.2 on an every 5-year basis or according to another testing/monitoring schedule as may be approved by the Department. CHS shall perform the test methods and procedures as specified in 40 CFR 63.425, Subpart R (ARM 17.8.105 and 17.8.342).
3. The product loading rack VCU shall be tested for CO and NO_x, concurrently, and compliance demonstrated with the CO and NO_x emission limitations contained in Section VI.B.2.b and c. Testing shall be conducted as requested by the Department (ARM 17.8.105).

F. Operational and Emission Inventory Reporting Requirements

CHS shall supply the Department with the following reports, as required by 40 CFR Part 63 (ARM 17.8.342).

1. Subpart CC - CHS shall keep all records and furnish all reports to the Department as required by 40 CFR Part 63.428 (b) and (c), (g)(1), and (h)(1) through (h)(3) of Subpart R.
2. Subpart CC - CHS shall keep all records and furnish all reports to the Department as required by 40 CFR Part 63.655 of Subpart R.

Section VII: Limitations and Conditions for the No. 1 Crude Unit

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60 for the No. 1 Crude Unit. The following subparts, at a minimum, are applicable (ARM 17.8.340):

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
2. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, applies to the No. 1 Crude Unit fugitive piping equipment in VOC service as appropriate.

- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):
1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (Refinery MACT I).
- C. Emission Control Requirements for No. 1 Crude Unit (ARM 17.8.752):
1. The No. 1 Crude Unit shall be maintained and operated as per the Leak Detection and Repair (LDAR) Program. The LDAR program would apply to new equipment in both HAP and non-HAP VOC service in the No. 1 Crude Unit. The LDAR program would not apply to existing equipment in non-HAP service undergoing retrofit measures.
 2. CHS shall monitor and maintain all pumps, shutoff valves, relief valves and other piping and valves associated (as defined above) with the No. 1 Crude Unit as described in 40 CFR 60.482-1 through 60.482-10. Records of monitoring and maintenance shall be maintained on site for a minimum of 2 years.
- D. Monitoring Requirements
- CHS shall monitor with the LDAR database the type and number of new fugitive VOC components added (ARM 17.8.749).
- E. Operational and Emission Inventory Reporting Requirements
- CHS shall comply with the recordkeeping and reporting requirements contained in 40 CFR 60, Subpart VVa (ARM 17.8.340 and 40 CFR 60, Subpart GGGa).

Section VIII: Limitations and Conditions for the ULSD Unit (900 Unit) and Hydrogen Plant (1000 Unit)

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping, and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable (ARM 17.8.340):
1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
 2. Subpart J - Standards of Performance for Petroleum Refineries applies to the two ULSD Unit heaters (H-901 and H-902).
 3. Subpart Ja - Standards of Performance for Petroleum Refineries applies to the H-1001 Reformer Heater.

4. Subpart GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the ULSD Unit and the Hydrogen Plant fugitive piping equipment in VOC service.
 5. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the ULSD Unit and Hydrogen Plant process drains.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAP for Source Categories (ARM 17.8.342).
1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 2. Subpart CC - NESHAP from Petroleum Refineries shall apply to, but not be limited to, Tank 96 when it is utilized in gasoline service.
- C. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in the ULSD Unit and Hydrogen Plant (ARM 17.8.304 (2)).
- D. Limitations on Individual Sources (ARM 17.8.752)
1. Reactor Charge Heater H-901
 - a. SO₂ emissions from H-901 shall not exceed (ARM 17.8.752):
 - i. 1.96 tons/rolling 12-calendar month total
 - ii. 0.90 lb/hr
 - b. NO_x emissions from H-901 shall not exceed (ARM 17.8.752):
 - i. 2.86 tons/rolling 12-calendar month total
 - ii. 0.65 lb/hr based on a 24-hour rolling average (recalculated hourly)
 - c. CO emissions from H-901 shall not exceed 11.76 tons/rolling 12-calendar month total (ARM 17.8.752).
 - d. VOC Emissions from H-901 shall not exceed 0.77 tons/rolling 12-calendar month total (ARM 17.8.752).
 - e. CHS shall not fire fuel oil in this unit (ARM 17.8.752 and ARM 17.8.749).
 2. Fractionator Reboiler H-902
 - a. SO₂ emissions from H-902 shall not exceed (ARM 17.8.752):

- i. 3.95 tons/rolling 12-calendar month total
 - ii. 1.80 lb/hr
 - b. NO_x emissions from H-902 shall not exceed (ARM 17.8.752):
 - i. 5.70 tons/rolling 12-calendar month total
 - ii. 1.30 lb/hr based on a rolling 24-hour average (recalculated hourly)
 - c. CO emissions from H-902 shall not exceed (ARM 17.8.752):

11.01 tons/rolling 12-calendar month total
 - d. VOC Emissions from H-902 shall not exceed 1.54 tons/rolling 12-calendar month total (ARM 17.8.752).
 - e. CHS shall not fire fuel oil in this unit (ARM 17.8.752 and ARM 17.8.749).
3. Reformer Heater H-1001
- a. The H-1001 Reformer Heater shall be equipped with ULNBs (ARM 17.8.752).
 - b. All available 1000 Unit PSA purge gas (sulfur free) shall be fired in the H-1001 Reformer Heater except during periods of startup, shutdown, operational transition, or process upset (ARM 17.8.752).
 - c. CHS shall not burn in the H-1001 Reformer Heater any fuel gas that contains H₂S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60, Subpart Ja).
 - d. NO_x emissions from H-1001 shall not exceed:
 - i. 40 ppmv (dry basis, corrected to 0 percent excess air) based on a 30-day rolling average (40 CFR 60, Subpart Ja).
 - ii. 29.4 tons per rolling 12-calendar month total (ARM 17.8.752).
 - iii. 7.7 lb/hr based on a rolling 24-hour average (ARM 17.8.752).
 - e. CO emissions from H-1001 shall not exceed (ARM 17.8.752):
 - i. 16.8 tons per rolling 12-calendar month total.
 - ii. 7.7 lb/hr during periods of startup and shutdown, based on a 24-hour rolling average.

- f. CO, VOC and PM/PM₁₀ emissions shall be controlled by proper design and good combustion practices (ARM 17.8.752).
- g. CHS shall not fire fuel oil in this unit (ARM 17.8.752 and ARM 17.8.749).

E. Monitoring Requirements

- 1. CHS shall install and operate the following CEMS/CERMS for the Reactor Charge Heater H-901 and the Fractionator Reboiler H-902 (ARM 17.8.749):
 - a. NO_x
 - b. Volumetric flowrate monitor
- 2. CEMS/CERMS shall comply with Appendix B of 40 CFR 60, Performance Specifications 2, 3, and 6; and Appendix F of 40 CFR 60. The required volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1. These requirements are referenced and considered applicable to these monitors based on ARM 17.8.749.
- 3. CHS shall install and operate the following (CEMS/CERMS) for H-1001:
 - a. NO_x/O₂ (40 CFR 60, Subpart Ja)
 - b. CO (ARM 17.8.749)
 - c. Volumetric flow rate monitor
- 4. CEMS and CERMS required for H-1001 shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subparts Ja, 60.100a-108a, and Appendix B, Performance Specifications 2, 3, 4A, and Appendix F. The required volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1.
- 5. All CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.
- 6. Compliance with the Reformer Heater H-1001 NO_x and CO emission limits shall be determined using the NO_x/CO CEMs and the volumetric stack flow rate monitor (with appropriate moisture correction, determined from the annual stack test data (RATA)).
- 7. Compliance with the H-901 and H-902 NO_x emission limits shall be determined using the NO_x CEMs and the volumetric stack flow rate monitor (with appropriate moisture correction, determined from the annual stack test

data (RATA)). Compliance with the H-901 and H-902 CO emission limits shall be determined from emissions factors generated from the most recent CO stack test (CO testing, concurrent with NO_x testing, as required by Section VIII.F.2 and VIII.F.3).

F. Testing Requirements

1. The Reactor Charge Heater (H-901) shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits of the H-901 process heater (ARM 17.8.105 and ARM 17.8.749).
2. The Fractionator Reboiler (H-902) shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits of the H-902 process heater (ARM 17.8.105 and ARM 17.8.749).
3. The Reformer Heater (H-1001) shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits of the H-1001 process heater, as applicable (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations (ARM 17.8.749)

1. In addition to stack testing required in Section VIII.F, compliance determinations for the NO_x limit for H-901, H-902, and H-1001 shall also be based upon monitoring data as required in Section VIII.E.
2. Compliance with the opacity limitation listed in Section VIII.C shall be determined using EPA Reference Method 9 testing by a qualified observer.

H. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

1. For the H-901 and H-902, CHS shall submit quarterly electronic emission reports to the Department based on data from the installed CEMS/CERMS. Emission reporting for NO_x from the emission monitors shall consist of the maximum 24-hour rolling average (determined hourly) for each calendar day. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service). The quarterly report shall also include the following:
 - a. Monitoring downtime that occurred during the reporting period.

- b. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in VIII.D.1 through VIII.D.2. Excess emissions shall be calculated in the same fashion as required by 40 CFR Part 60.
 - c. Compliance determinations for hourly and annual limits specifically allowed in Sections VIII.D.1 through VIII.D.2. Calculations shall utilize all valid data (ARM 17.8.749).
 - d. Reasons for any emissions in excess of those specifically allowed in Sections VIII.D.1 through VIII.D.2 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.
- 2. For the H-1001, CHS shall submit quarterly emission reports to the Department based on data from the installed CEMS/CERMS. Emission reporting for NO_x and CO from the emission monitors shall consist of a daily maximum 1-hour average (ppm) for each calendar day. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service). The quarterly report shall also include the following:
 - a. The daily and monthly NO_x averages in ppm, corrected to 0% O₂.
 - b. Monitoring downtime that occurred during the reporting period.
 - c. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section VIII.D.3.
 - d. Compliance determinations for hourly, 30-day, and annual limits specifically allowed in Section VIII.D.3 (ARM 17.8.749).
 - e. Reasons for any emissions in excess of those specifically allowed in Sections VIII.D.3 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

Section IX: Limitations and Conditions for the TGTU for Zone A's SRU #1 and SRU #2 trains and Zone A's Sulfur Recovery Plants

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping, and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable (ARM 17.8.340):
 - 1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
 - 2. Subpart J - Standards of Performance for Petroleum Refineries applies to Zone A's SRU #1 and #2 tail gas incinerator (SRU-AUX-4) stack.

3. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the TGTU process drains as applicable.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAP for Source Categories (ARM 17.8.342).
 1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 2. Subpart UUU - MACT Standard for Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. CHS shall comply with Subpart UUU by complying with 40 CFR Part 60, NSPS Subpart J.
- C. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in the TGTU (ARM 17.8.304 (2)).
- D. The Department determined, based on modeling provided by CHS, that the SRU-AUX-4 stack shall be maintained at a height no less than 132 feet.
- E. Limitations on Individual Sources
 1. SO₂ emissions from the SRU-AUX-4 stack shall not exceed:
 - a. 250 ppm, rolling 12-hour average corrected to 0% oxygen, on a dry basis (ARM 17.8.749 and 40 CFR Part 60, Subpart J)
 - b. 200 ppm, rolling 12-month average corrected to 0% oxygen, on a dry basis (ARM 17.8.752)
 - c. 40.66 tons/rolling 12-month total
 - d. 11.60 lb/hr
 - e. 278.40 lb/day
 2. NO_x emissions from the SRU-AUX-4 stack shall not exceed:
 - a. 4.8 tons/rolling 12-calendar month total
 - b. 1.09 lb/hr
 3. CHS shall not fire fuel oil in this unit (ARM 17.8.749).
- F. Monitoring Requirements
 1. CHS shall install and operate the following CEMS/CERMS on the Zone A SRU-AUX-4 Stack:

- a. SO₂ (40 CFR 60, Subpart J and Billings SO₂ SIP)
 - b. O₂ (40 CFR 60, Subpart J)
 - c. Volumetric Flow Rate (Billings SO₂ SIP)
2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts J, 60.100-108 and Appendix B, Performance Specifications 2, 3, 6, and Appendix F. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1.
 3. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.

G. Testing Requirements

The SRU-AUX-4 Stack shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department for SO₂ and shall be tested on an every 6-year basis, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x. The results shall be submitted to the Department in order to demonstrate compliance with the SO₂ and NO_x emission limits contained in Sections IX.E.1, 2, and 3 (ARM 17.8.105 and ARM 17.8.749).

H. Compliance Determinations (ARM 17.8.749)

1. In addition to the testing required in Section IX.G, compliance determinations for ppm concentration, hourly, 3-hour, 24-hour, rolling 12-month, and annual SO₂ limits for the SRU-AUX-4 Stack shall be based upon CEMS data utilized for SO₂ as required in Section IX.F.1.
2. Compliance with the opacity limitation listed in Section IX.C shall be determined using EPA reference method 9 testing by a qualified observer.

I. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

Emission reporting for SO₂ from the emission rate monitors shall consist of a daily 24-hour average concentration (ppm SO₂, corrected to 0% O₂) and a 24-hour total (lb/day) for each calendar day. CHS shall submit a quarterly emission report within 30 days of the end of each calendar quarter. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or uploaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service). The quarterly report shall also include the following:

1. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates.
2. Monitoring downtime that occurred during the reporting period.
3. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section IX.E.
4. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section IX.E.
5. Reasons for any emissions in excess of those specifically allowed in Section IX.E with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

Section X: Limitations and Conditions for the FCCU and related units

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable:
 1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
 2. Subpart J - Standards of Performance for Petroleum Refineries applies to the FCCU Regenerator for SO₂, CO, and PM.
 3. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (The FCCU Regenerator Stack is subject to NSPS Subpart Ja for CO only, and the FCCU Charge Heater (FCC-Htr-1) is subject to the fuel gas combustion device and process heater requirements).
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):
 1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 2. Subpart CC - Refinery MACT I shall apply to, but not be limited to, certain parts of the FCCU piping.
 3. Subpart UUU - Refinery MACT II shall apply to, but not be limited to, the FCCU.
- C. Opacity
 1. CHS shall not cause or authorize emissions to be discharged from the FCCU Regenerator Stack into the outdoor atmosphere that exhibit an opacity

greater than 30%, except for one six-minute average opacity reading in any one hour period (ARM 17.8.304, ARM 17.8.340, 40 CFR Part 60, Subpart J).

2. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304). During the building of new fires, cleaning of grates, or soot blowing, the provisions of ARM 17.8.304(1) and (2) shall apply, except that a maximum average opacity of 60% is permissible for not more than one 4-minute period in any 60 consecutive minutes. Such a 4-minute period means any 4 consecutive minutes (ARM 17.8.304(3)).

D. Limitations on Individual Emitting Units

1. FCCU Regenerator Stack

- a. CO emissions from the FCCU Regenerator Stack shall not exceed 500 ppmv, dry basis corrected to 0% excess air, on an hourly average basis (ARM 17.8.340, 40 CFR Part 60, Subpart Ja, and ARM 17.8.752).
- b. CO emissions from the FCCU Regenerator Stack shall not exceed 100 ppm_{vd} at 0% O₂, on a 365-day rolling average basis (ARM 17.8.749).
- c. CHS shall not exceed 50 ppm SO₂ by volume (corrected to 0% O₂) on a 7-day rolling average and shall also comply with an SO₂ concentration limit of 25 ppm_{vd} at 0% O₂ on a 365-day rolling average basis (ARM 17.8.340, 40 CFR Part 60, Subpart J, and ARM 17.8.752).
- d. PM emissions from the FCCU Regenerator Stack shall be controlled with an ESP. PM emissions from the FCCU Regenerator Stack shall not exceed 1.0 lb PM/1,000 lb of coke burned (ARM 17.8.340, 40 CFR Part 60, Subpart J, and ARM 17.8.752).
- e. NO_x emissions from the FCCU Regenerator Stack shall not exceed 65.1 ppm_{vd} at 0% oxygen on a 365-day rolling average basis. This long-term limit shall apply at all times (including during startup, shutdown, and malfunction), that the FCCU Regenerator Stack is operating (ARM 17.8.749 and ARM 17.8.752).
- f. NO_x emissions from the FCCU Regenerator Stack shall not exceed 102 ppm_{vd} at 0% oxygen on a 7-day rolling average basis. This short-term limit shall exclude periods of startup, shutdown, and malfunction, but shall apply at all other times that the FCCU is operating. For days and hours in which the FCCU Regenerator Stack is not operating, no NO_x value shall be used in the average, and those periods shall be skipped in determining compliance with the 7-day and 365-day averages (ARM 17.8.749 and ARM 17.8.752).
- g. NO_x emissions from the FCCU Regenerator Stack shall not exceed 117 tons per 12-month rolling average (limit is based on 65.1 ppm_{vd} at 0% oxygen on a 365-day rolling average) (ARM 17.8.749).

- h. CO and VOC emissions from the FCCU Regenerator stack shall be controlled through the use of CO combustion promoters as needed, and good combustion practices. Compliance with the FCCU Regenerator Stack CO emission limits shall be used as a surrogate for VOCs (ARM 17.8.752).

2. FCC Charge Heater (FCC-Htr-1)

- a. The FCC-Htr-1 shall be equipped with ULNBs (ARM 17.8.752).
- b. NO_x emissions from FCC-Htr-1 shall not exceed:
 - i. 40 ppmv (dry basis, corrected to 0 percent excess air) based on a 30-day rolling average (40 CFR 60, Subpart Ja and ARM 17.8.752).
 - ii. 10.1 tpy based on a 12-calendar month total (ARM 17.8.752).
 - iii. 2.6 lb/hr based on a 24-hour rolling average (ARM 17.8.752).
- c. CO emissions from FCC-Htr-1 shall not exceed 100 ppmv at 3% oxygen based on a 24-hour rolling average (ARM 17.8.752).
- d. CHS shall not combust any fuel gas that contains H₂S in excess of 60 ppmv determined daily on a 365-successive calendar day rolling average basis (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60, Subpart Ja).
- e. CHS shall implement proper design and good combustion techniques to minimize CO, VOC, and PM/PM₁₀/PM_{2.5} emissions (ARM 17.8.752).

E. Monitoring Requirements

- 1. CHS shall install and operate the following CEMS/CERMS on the FCCU Regenerator Stack:
 - a. CO (40 CFR 60, Subpart Ja)
 - b. NO_x (ARM 17.8.749)
 - c. SO₂ (40 CFR 60, Subpart J, Billings/Laurel SO₂ SIP)
 - d. O₂ (40 CFR 60, Subpart J, Subpart Ja, and Billings/Laurel SO₂ SIP)
 - e. Opacity (40 CFR 60, Subpart J, 40 CFR 63, Subpart UUU)
 - f. Volumetric stack flow rate monitor (Billings/Laurel SO₂ SIP)
- 2. CHS shall install and operate the following on the FCC-Htr-1:
 - a. NO_x/O₂ CEMS (40 CFR 60, Subpart Ja)
 - b. Volumetric stack flow rate monitor (ARM 17.8.749)

3. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts J, 60.100-108, Subparts Ja, 60.100a-108a and Appendix B, Performance Specifications 1, 2, 3, 6, and Appendix F. The volumetric flow rate monitor(s) shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1.
4. The FCCU Regenerator Stack and FCC-Htr-1 CEMS, stack gas volumetric flow rate CEMS, and the fuel gas flow meters shall comply with all applicable requirements of the Billings/Laurel SO₂ SIP Emission Control Plan, including Exhibit A and Attachments, adopted by the Board of Environmental Review, June 12, 1998, and stipulated to by Cenex Harvest States Cooperative and its successor CHS.
5. Compliance with the emission limit in Section X.D.2.b shall be determined using the NO_x/O₂ CEMS and the volumetric stack flow rate monitor (with appropriate moisture correction).
6. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.

F. Testing Requirements

1. CHS shall follow the stack protocol specified in 40 CFR 60.106(b)(2) to measure PM emissions from the FCCU Regenerator stack. CHS shall conduct the PM tests every three years from the date of the last source test or on another testing schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.340, and 40 CFR 60, Subpart J).
2. The FCC Charge Heater (FCC-Htr-1) shall be tested every three years from the date of the last source test in conjunction with annual CEMS/CERMS RATA performance testing in accordance with Appendix F (40 CFR Part 60) requirements, or according to another testing/ monitoring schedule as may be approved by the Department, for NO_x/O₂ and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section X.D.2.b and X.D.2.c (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations

1. Compliance determinations for the FCCU Regenerator Stack emission limits in Section X.D for NO_x, CO, and SO₂ shall be based upon monitor data, as required in Section X.E.1.
2. Compliance determinations for the FCC-Htr-1 emission limits in Section X.D shall be based upon monitor data (for NO_x) or source test results (for NO_x and CO), as required in Section X.E.2 and X.F.2.

3. Compliance with the opacity limitations listed in Section X.C shall be determined using EPA reference method 9 observations by a qualified observer or a certified continuous opacity monitor system (COMS).

H. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

For the FCCU Regenerator Stack and the FCC-Htr-1, CHS shall submit quarterly emission reports to the Department based on data from the installed CEMS/CERMS. Emission reporting for SO₂ and CO (FCCU Regenerator Stack only) and NO_x from the emission monitors shall consist of a daily maximum 1-hour average (ppm) for each calendar day. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service). The quarterly report shall also include the following:

1. Source or unit operating time during the reporting period and the 7-day and 365-day rolling average SO₂ concentrations (ppmv).
2. The daily and monthly NO_x averages in ppm, corrected to 0% O₂.
3. Monitoring downtime that occurred during the reporting period.
4. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section X.D.1 and X.D.2.
5. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section X.D.1 and X.D.2 (ARM 17.8.749).
6. Reasons for any emissions in excess of those specifically allowed in Section X.D with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

Section XI: Limitations and Conditions for the Naphtha Hydrotreating Unit, Delayed Coker Unit (From MAQP #1821-13) and Zone E SRU/TGTU/TGI

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping, and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable (ARM 17.8.340):
 1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
 2. Subpart J - Standards of Performance for Petroleum Refineries applies to the NHT Charge Heater (H-8301), the Coker Charge Heater (H-7501), and the Zone E SRU/TGTU/TGI.
 3. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to the Coker Unit flare.

4. Subpart GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the Naphtha Hydrotreating Unit and the Delayed Coker Unit fugitive piping equipment in VOC service. Once the MUE Project is complete, the DCU and NHT process units will be required to comply with a program meeting requirements of Subpart GGGa.
 5. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the Delayed Coker Unit process drains.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):
1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 2. Subpart CC - Refinery MACT I shall apply to, but not be limited to, affected sources or the collection of emission points as defined in this subpart.
 3. Subpart UUU - Refinery MACT II shall apply to, but not be limited to, the Zone E SRU/TGTU/TGI.
- C. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in the Delayed Coker Unit (ARM 17.8.304 (2)).
- D. Limitations on Individual Sources
1. NHT Charge Heater (H-8301)
 - a. SO₂ emissions from the NHT Charge Heater (H-8301) shall not exceed (ARM 17.8.752):
 - i. 1.54 tons/rolling 12-calendar month total
 - ii. 0.70 lb/hr
 - b. NO_x emissions from the NHT Charge Heater (H-8301) shall not exceed (ARM 17.8.752):
 - i. 6.55 tons/rolling 12-calendar month total
 - ii. 1.50 lb/hr
 - c. CO emissions from the NHT Charge Heater (H-8301) shall not exceed 400 ppm_{vd} at 3% oxygen on a 30-day rolling average (ARM 17.8.752).
 - d. VOC Emissions from the NHT Charge Heater (H-8301) shall not exceed 0.86 tons/rolling 12-calendar month total (ARM 17.8.752).

- e. CHS shall not fire fuel oil in this unit (ARM 17.8.340; 40 CFR 60, Subpart J; and ARM 17.8.752).
2. Coker Charge Heater (H-7501)
 - a. SO₂ emissions from the Coker Charge Heater (H-7501) shall not exceed (ARM 17.8.752):
 - i. 6.61 tons/rolling 12-calendar month total
 - ii. 3.02 lb/hr
 - b. NO_x emissions from the Coker Charge Heater (H-7501) shall not exceed (ARM 17.8.752):
 - i. 28.2 tons/rolling 12-calendar month total
 - ii. 6.44 lb/hr
 - c. CO emissions from the Coker Charge Heater (H-7501) shall not exceed (ARM 17.8.752):
 - i. 400 ppm_{vd} at 3% oxygen on a 30-day rolling average
 - ii. 35.2 tons/rolling 12-calendar month total
 - iii. 8.05 lb/hr
 - d. During periods of startup, shutdown, and spalling (a feed heater coil decoking process completed during operation to avoid complete unit shutdown), CO emissions from the Coker Charge Heater (H-7501) shall not exceed 16.1 lb/hr on a 24-hour rolling average (ARM 17.8.752).
 - e. VOC Emissions from the Coker Charge Heater (H-7501) shall not exceed 1.41 tons/rolling 12-calendar month total (ARM 17.8.752).
 - f. CHS shall not fire fuel oil in this unit (ARM 17.8.340; 40 CFR 60, Subpart J; and ARM 17.8.752).
 3. The Coker unit flare shall operate with a continuous pilot flame and a continuous pilot flame-operating device and meet applicable control device requirements of 40 CFR 63.670 and 40 CFR 63.671 (40 CFR 63.670, 40 CFR 63.671 and ARM 17.8.752).
 4. VOC emissions from the Sour Water Storage Tank (TK-129) shall be controlled by the installation and use of an internal floating roof and a submerged fill pipe (ARM 17.8.752).
 5. VOC emissions from the Coker Sludge Storage Tank (TK-7504) shall be controlled by the installation and use of a fixed roof, a submerged fill pipe, and a conservation vent (ARM 17.8.752).

6. Coke processing operations
 - a. CHS shall store onsite coke in the walled enclosure for coke storage only. Onsite coke storage shall be limited to a volume that is contained within the walled enclosure. Storage of coke outside of the walled enclosure is prohibited (ARM 17.8.752).
 - b. The coke pile shall not exceed the height of the enclosure walls adjacent to the pile at any time (ARM 17.8.752).
 - c. CHS shall not cause or authorize emissions to be discharged into the atmosphere from coke handling without taking reasonable precautions to control emissions of airborne particulate matter. CHS shall wet the coke as needed to comply with the reasonable precautions standard (ARM 17.8.308 and ARM 17.8.752).
 - d. CHS shall install and maintain enclosures surrounding the coke conveyors, coke transfer drop points (not including the location at which coke is transferred from the front-end loader to the initial coke sizing screen), and crusher (ARM 17.8.752).
 - e. CHS shall install and maintain a telescoping loading spout for loading coke into railcars and trucks (ARM 17.8.752).
 - f. Alternate Coke Handling Method: In the event the conveyors are inoperable (as described in Section XI.D.6.d and e) due to either planned or unplanned maintenance activities, CHS may transport uncrushed coke only from the coke storage area to the railcar using a front-end loader. The requirements specified in Section XI.D.6.a – c still apply. The alternate coke handling method is limited to 24 batches per year (ARM 17.8.752).
 - g. CHS 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. CHS shall treat unpaved coke trucking transport roads with water and/or chemical dust suppressant as necessary to control emissions while coke is being transported from the refinery (ARM 17.8.308 and ARM 17.8.752).
 - h. CHS shall clean the paved sections of coke transport roads, as necessary, for reasonable precautions specific to truck hauling of coke on refinery property (ARM 17.8.308 and ARM 17.8.752).
 - i. CHS shall cover the coke during truck transport of the coke from the refinery (ARM 17.8.752).
 - j. CHS shall load no more than 175,200 tons of coke into trucks per year, as determined monthly on a rolling 12-month period (ARM 17.8.749).
7. Zone E SRU/TGTU/TGI

- a. SO₂ emissions from the Zone E SRU/TGTU/TGI shall not exceed (ARM 17.8.752):
 - i. 49.4 tons/rolling 12-calendar month total (based on 200 ppm, rolling 12-month average corrected to 0% oxygen, on a dry basis)
 - ii. 14.1 lb/hr (based on 250 ppm, rolling 12-hour rolling average corrected to 0% oxygen, on a dry basis)
 - b. CHS shall operate and maintain the TGTU on the Coker Unit to limit SO₂ emissions from the Coker Unit stack to no more than 200 ppm on a rolling 12-month average corrected to 0% oxygen on a dry basis.
 - c. NO_x emissions from the Zone E SRU/TGTU/TGI shall not exceed (ARM 17.8.749):
 - i. 4.62 tons/rolling 12-calendar month total
 - ii. 1.05 lb/hr
 - d. CHS shall not cause or authorize to be discharged into the atmosphere from the TGI:
 - i. Any visible emissions that exhibit an opacity of 10% or greater (ARM 17.8.752)
 - ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO₂ (ARM 17.8.752)
8. CHS is required to operate and maintain a mist eliminator on the Coker Cooling Tower that limits PM₁₀ emissions to no more than 0.002% of circulating water flow (ARM 17.8.752).
9. Coke Drum Steam Vent
- a. VOC emissions from the Coke Drum Steam Vent shall not exceed 18.10 tons/yr as determined on a monthly rolling 12-month total (ARM 17.8.749).
 - b. PM₁₀ emissions from the Coke Drum Steam Vent shall not exceed 4.52 tons/yr as determined on a monthly rolling 12-month total (ARM 17.8.749).
 - c. CHS shall depressure each coke drum to a closed blowdown system until either (ARM 17.8.342 and 40 CFR 63 Subpart C):
 - i. The coke drum average pressure is 2 psig or or less, determined on a rolling 60-event average or:
 - ii. The coke drum average vessel temperature is 220 degrees Fahrenheit or less, determined on a rolling 60-event average.

E. Monitoring requirements

1. CHS shall install and operate the following (CEMS/CERMS):
Zone E SRU/TGTU/TGI (Billings/Laurel SO₂ SIP)
 - a. SO₂ (40 CFR 60, Subpart J)
 - b. O₂ (40 CFR 60, Subpart J)
 - c. Volumetric Flow Rate (ARM 17.8.749)
2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subparts J, 60.100-108, and Appendix B, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1 (ARM 17.8.749).
3. The Delayed Coker Unit SO₂ CEMS, stack gas volumetric flow rate CEMS, and fuel gas flow rate meters shall comply with all applicable requirements of the Billings/Laurel SO₂ SIP Emission Control Plan, including Exhibit A and Attachments, adopted by the Board of Environmental Review, June 12, 1998, and stipulated to by Cenex Harvest States Cooperative and its successor CHS (ARM 17.8.749).
4. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated (ARM 17.8.749).
5. CHS shall continuously monitor the pressure in the coke drums such that the pressure at which each drum is depressurized can be determined (40 CFR 63 657 and ARM 17.8.749).

F. Testing Requirements

1. The NHT Charge Heater (H-8301) shall be tested every 2 years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section XI.D.1.b and c (ARM 17.8.105 and ARM 17.8.749).
2. The Coker Charge Heater (H-7501) shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to

demonstrate compliance with the NO_x and CO emission limits contained in Section XI.D.2.b and c (ARM 17.8.105 and ARM 17.8.749).

3. The Zone E SRU/TGTU/TGI stack shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department for SO₂, and shall be tested on an every 6-year basis, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x. The results shall be submitted to the Department in order to demonstrate compliance with the SO₂ and NO_x emission limits contained in Section XI.D.7.a, b, and c, respectively (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations (ARM 17.8.749).

1. In addition to the testing required in Section XI.F, compliance determinations for ppm concentration, hourly, and rolling 12-month SO₂ limits for the Zone E SRU/TGTU/TGI shall be based upon CEMS data utilized for SO₂ as required in Section XI.E.1 (ARM 17.8.749).
2. Compliance with the opacity limitation listed in Section XI.C shall be determined using EPA reference method 9 observations by a qualified observer or a certified COMS.
3. Using the following equations, CHS shall determine the VOC and PM₁₀ emissions from the Coke Drum Steam Vent each time a steam vent is opened to the atmosphere (cycle). CHS shall sum emissions from all cycles on a rolling 12-month basis to determine compliance with the emissions limits (ARM 17.8.749).

$$PM_{10}, lb / cycle = \left(\frac{15}{2} / \frac{65}{4} \right) (-1.5041P^2 + 17.603P + 3.7022)$$

$$VOC, lb / cycle = \left(\frac{15}{2} / \frac{65}{4} \right) (2.6378P^3 - 33.487P^2 + 144.5P - 37.706)$$

P = 5-minute rolling average coke drum pressure (psig) as determined just prior to initiating steps to isolate the coke drum prior to venting, draining or deheading.

H. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

1. CHS shall prepare and submit a quarterly emission and coke handling report within 30 days of the end of each calendar quarter. Emission reporting for SO₂ from the emission rate monitors shall consist of a daily 24-hour average concentration (ppm SO₂, corrected to 0% O₂) and a 24-hour total (lb/day) for each calendar day. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service). The quarterly report shall also include the following (ARM 17.8.749).

- a. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates.
- b. Monitoring downtime that occurred during the reporting period.
- c. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in XI.D.1 through 2, 7 and 8.
- d. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section XI.G.
- e. Reasons for any emissions in excess of those specifically allowed in Section XI.D.1 through 2, 7 and 8 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.
- f. A summary of the number of batches of coke that were processed using the alternative coke handling method.
- g. The rolling 12-month total tons of coke transported by truck.

Section XII: Limitations and Conditions for Boiler #11

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping, and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable (ARM 17.8.340):
 1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
 2. Subpart J - Standards of Performance for Petroleum Refineries applies to Boiler #11.
 3. Subpart Db - Standards of Performance for Steam Generating Units applies to Boiler #11.
 4. Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006 applies to Boiler #11.
- B. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in Boiler #11 (ARM 17.8.304 (2)).
- C. Limitations on Boiler #11
 1. SO₂ emissions from Boiler #11 shall not exceed (ARM 17.8.752):
 - a. 8.59 tons/rolling 12-calendar month total

- b. 3.92 lb/hr
- 2. NO_x emissions from Boiler #11 shall not exceed (ARM 17.8.752):
 - a. 27.5 tons/rolling 12-calendar month total (ARM 17.8.752)
 - b. 6.27 lb/hr, rolling 365-day average (ARM 17.8.752)
- 3. During periods of startup or shutdown, CO emissions from Boiler #11 shall not exceed 23 lb/hr on a 24-hour rolling average (ARM 17.8.752). Otherwise, CO emissions shall not exceed (ARM 17.8.752):
 - a. 400 ppm_{vd} at 3% oxygen on a 30-day rolling average
 - b. 36.63 tons/rolling 12-calendar month total
 - c. 15.26 lb/hr
- 4. VOC Emissions from the Boiler #11 shall not exceed 4.83 tons/rolling 12-calendar month total (ARM 17.8.752).
- 5. CHS shall not fire fuel oil in this unit (ARM 17.8.340; 40 CFR 60, Subpart J; and ARM 17.8.752).

D. Monitoring requirements

- 1. CHS shall install and operate the following (CEMS/CERMS) for Boiler #11:
 - a. NO_x (40 CFR 60, Subpart Db)
 - b. O₂ (40 CFR 60, Subpart Db)
- 2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subpart Db; 60.40b through 60.49b, and Appendix A, Appendix B, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F.
- 3. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.
- 4. CHS shall install and operate a volumetric stack flow rate monitor on Boiler #11. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1. The volumetric stack flow rate monitor is required within 180 days of the issuance of MAQP #1821-21 (ARM 17.8.749).

E. Testing Requirements

Boiler #11 shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Sections XII.C.2 and 3 (ARM 17.8.105 and ARM 17.8.749).

F. Compliance Determinations (ARM 17.8.749)

1. In addition to stack testing required in Section XII.E, compliance determinations for the NO_x limit in Section XII.C for Boiler #11 shall also be based upon monitoring data as required in Section XII.D.
2. Compliance with the opacity limitation listed in Section XII.B shall be determined using EPA Reference Method 9 observations by a qualified observer or a certified COMS.
3. Compliance with the lb/MMBtu limit(s) will be demonstrated using statistically significant F-factor values. The factor will be updated on a regular basis using data from all valid fuel gas samples representative of the fuel gas burned in Boiler #11. The method of compliance demonstration involving F-factor statistical significance is subject to change upon agreement with the Department and CHS (40 CFR 60, Appendix A, Reference Method 19).

G. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

CHS shall prepare and submit a quarterly emission report within 30 days of the end of each calendar quarter. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service). The quarterly report shall also include the following:

1. SO₂ emission data from the refinery fuel gas system continuous H₂S concentration monitor required by Section III. The SO₂ emission rates shall be reported for the following averaging periods:
 - a. Average lb/hr per calendar day
 - b. Total lb per calendar day
 - c. Total tons per month
2. NO_x emission data from the CEMS, fuel gas flow rate meter, and emission factors developed from the most recent compliance source test. The NO_x emission rates shall be reported for the following averaging periods:
 - a. Average lb/MMBTU per calendar day
 - b. Total tons per month

- c. lb/MMBTU per rolling 30-day average
- 3. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates.
- 4. Monitoring downtime that occurred during the reporting period.
- 5. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section XII.C.1 through 4.
- 6. Reasons for any emissions in excess of those specifically allowed in Section XII.C with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

Section XIII: Limitations and Conditions for the Railcar Light Product Loading Rack and Vapor Combustion Unit (VCU) and Railcar Gasoline Component Unloading

- A. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements of ARM 17.8.342, as specified in 40 CFR Part 63, NESHAP for Source Categories.
 - 1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 - 2. Subpart CC - Refinery MACT I shall apply to, but not be limited to, the product loading rack and VCU. The Gasoline Loading Rack provisions in Subpart CC require compliance with certain Subpart R provisions.
- B. The Railcar Light Product Loading Rack and VCU shall be operated and maintained as follows:
 - 1. CHS' railcar light product loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from railcars during gasoline product loading (ARM 17.8.342 and ARM 17.8.752).
 - 2. CHS' collected vapors shall be routed to the VCU at all times. In the event the VCU is inoperable, CHS 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 17.8.749).
 - 3. Loadings of liquid products 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 ARM 17.8.752).

C. Railcar Gasoline Component Unloading

1. CHS shall implement proper design and operating practices while unloading gasoline components via railcars (ARM 17.8.752).
2. A monitoring and maintenance program, as described under 40 CFR 60, Subpart VVa, and meeting the requirements of 40 CFR 60, Subpart GGa shall be instituted (ARM 17.8.752).

D. Emission Limitations for the Railcar Light Product Loading Rack VCU

1. 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).
2. 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).
3. 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).
4. CHS shall not cause or authorize to be discharged into the atmosphere from the VCU:
 - a. Any visible emissions that exhibit an opacity of 10% or greater (ARM 17.8.752); and
 - b. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO₂ (ARM 17.8.752).

E. Monitoring and Testing Requirements

1. CHS shall perform the testing and monitoring procedures, as applicable, specified in 40 CFR 63, Subpart R (ARM 17.8.342 and 40 CFR 63, Subpart CC).
2. CHS shall install and continuously operate a thermocouple and an associated recorder for temperature monitoring in the firebox or ductwork immediately downstream in a position before any substantial heat occurs and develop an operating parameter value in accordance with the provisions of 40 CFR 63.425 and 63.427 for the VCU. CHS shall install and continuously operate an ultraviolet flame detector and relay system which will render the loading rack inoperable if a flame is not present at the VCU firebox or any other equivalent device, to detect the presence of a flame (ARM 17.8.342 and ARM 17.8.752).

3. The VCU shall be initially tested for VOCs every 5 years, or according to another testing/monitoring schedule as may be approved by the Department. CHS shall perform the test methods and procedures as specified in 40 CFR 63.425, Subpart R (ARM 17.8.105 and 17.8.342).
 4. The VCU shall be tested for CO and NO_x, concurrently, and compliance demonstrated with the CO and NO_x emission limitations contained in Section XIII.C.2 and 3. Testing shall be conducted as requested by the Department (ARM 17.8.105).
- F. Operational and Emission Inventory Reporting Requirements (Railcar Gasoline Component Unloading)
1. CHS shall record the number of gallons of gasoline component material unloaded and the subsequent Reid vapor pressure of the material and shall report this information with the annual emissions inventory submittal (ARM 17.8.749).
 2. CHS shall comply with the recordkeeping and reporting requirements contained in 40 CFR 60, Subpart VVa (ARM 17.8.749).

Section XIV: Limitations and Conditions for Boiler #12

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping, and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable (ARM 17.8.340):
1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
 2. Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units applies to Boiler #12.
 3. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to Boiler #12, which meets the NSPS Subpart Ja definition of a “fuel gas combustion device.”
 4. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to the refinery fuel gas supply lines to Boiler #12.
- B. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in Boiler #12 (ARM 17.8.304 (2)).

C. Limitations on Boiler #12

1. SO₂ emissions from Boiler #12 shall not exceed (40 CFR 60, Subpart Ja, ARM 17.8.340, ARM 17.8.752):
 - a. 60 ppmvd H₂S refinery fuel gas, on a rolling 365-calendar day average
 - b. 5.84 tons/rolling 12-calendar month total
 - c. 3.60 lb/hr
2. NO_x emissions from Boiler #12 shall not exceed (ARM 17.8.752):
 - b. 27.5 tons/rolling 12-calendar month total (ARM 17.8.752)
 - c. 6.27 lb/hr, rolling 365-day average (ARM 17.8.752)
3. During periods of startup or shutdown, CO emissions from Boiler #12 shall not exceed 23 lb/hr on a 24-hour rolling average (ARM 17.8.752). Otherwise, CO emissions shall not exceed (ARM 17.8.752):
 - a. 400 ppm_{vd} at 3% oxygen on a 30-day rolling average
 - b. 36.63 tons/rolling 12-calendar month total
 - c. 15.26 lb/hr
4. VOC Emissions from the Boiler #12 shall not exceed 4.81 tons/rolling 12-calendar month total (ARM 17.8.752).
5. Boiler #12 shall be fitted with ultra-low NO_x burners with FGR (ARM 17.8.752).
6. CHS shall not fire fuel oil in this unit (ARM 17.8.749 and ARM 17.8.752).

D. Monitoring requirements

1. CHS shall install and operate the following (CEMS/CERMS) for Boiler #12:
 - a. NO_x (40 CFR 60, Subpart Db)
 - b. O₂ (40 CFR 60, Subpart Db)
2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subpart Db 60.40b through 60.49b, Subparts Ja, 60.100a-108a, and Appendix A, Appendix B, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F (ARM 17.8.749 and ARM 17.8.342).

3. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated (ARM 17.8.749).
4. With exception to the initial performance test period, compliance with the lb/MMBtu limit(s) will be demonstrated using statistically significant F-factor values. The factor will be updated on a regular basis using data from all valid fuel gas samples representative of the fuel gas burned in Boiler #12. The method of compliance demonstration involving F-factor statistical significance is subject to change upon agreement with the Department and CHS (40 CFR 60, Appendix A, Reference Method 19).
5. CHS shall install and operate a volumetric stack flow rate monitor on Boiler #12. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1 (ARM 17.8.749).

E. Testing Requirements

Boiler #12 shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Sections XIV.C.2 and 3 (ARM 17.8.105 and ARM 17.8.749).

F. Compliance Determinations (ARM 17.8.749).

1. Compliance with the opacity limitation listed in Section XIV.B shall be determined using EPA Reference Method 9 observations by a qualified observer or a certified COMS.
2. Compliance with the limit in Section XIV.C.2.c. shall be determined using the NO_x CEM required in Section XIV.D.1 and the volumetric stack flow rate monitor required in Section XIV.D.5.

G. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)
CHS shall prepare and submit a quarterly emission report within 30 days of the end of each calendar quarter. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service). The quarterly report shall also include the following:

1. SO₂ emission data from the refinery fuel gas system continuous H₂S concentration monitor required by Section III. The SO₂ emission rates shall be reported for the following averaging periods:
 - a. Average lb/hr per calendar day

- b. Total lb per calendar day
 - c. Total tons per month
- 2. NO_x emission data from the CEMS, fuel gas flow rate meter, and emission factors developed from the most recent compliance source test. The NO_x emission rates shall be reported for the following averaging periods:
 - a. Average lb/MMBTU per calendar day
 - b. Total tons per month
 - c. lb/MMBTU per rolling 30-day average
 - d. lb/MMBtu per rolling 365-day average
 - e. Daily average and maximum lb/hr
- 3. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates.
- 4. Monitoring downtime that occurred during the reporting period.
- 5. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section XIV.C.1 through 4.
- 6. Reasons for any emissions in excess of those specifically allowed in Section XIV.C with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

Section XV: Benzene Reduction Unit (BRU)

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable:
 - 1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
 - 2. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to the Platformer Splitter Reboiler. The process heater NO_x requirements do not apply to the Platformer Splitter Reboiler because its rated capacity is less than 40 MMBtu/hr.
 - 3. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, applies to all of the fugitive VOC emitting components added in the affected facility.

4. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply to, but not be limited to, any new, modified, or reconstructed affected facility associated with the benzene reduction project.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):
 1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (Refinery MACT I) applies to certain parts of the Benzene Reduction Unit.
- C. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in the Benzene Reduction Unit (ARM 17.8.304 (2)).
- D. Limitations on Platformer Splitter Reboiler
 1. SO₂ emissions from the Platformer Splitter Reboiler shall not exceed:
 - a. 60 ppm_v H₂S in refinery fuel gas, 365-day rolling average for the Platformer Splitter Reboiler (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60, Subpart Ja)
 - b. 1.18 tons/ rolling 12-calendar month total (ARM 17.8.749)
 - c. 0.72 lb/hr (ARM 17.8.749)
 2. NO_x emissions from the Platformer Splitter Reboiler shall not exceed:
 - a. 6.99 tons/ rolling 12-calendar month total (ARM 17.8.749)
 - b. 1.60 lb/hr (ARM 17.8.752)
 3. CO emissions from the Platformer Splitter Reboiler shall not exceed:
 - a. 13.62 tons/ rolling 12-calendar month total (ARM 17.8.749)
 - b. 3.11 lb/hr (ARM 17.8.752)
 4. PM/PM₁₀ emissions from the Platformer Splitter Reboiler shall not exceed:
 - a. 1.31 tons/ rolling 12-calendar month total (ARM 17.8.749)
 - b. 0.30 lb/hr (ARM 17.8.752)

5. VOC emissions from the Platformer Splitter Reboiler shall not exceed 0.64 tons/rolling 12-calendar month total (ARM 17.8.752).
6. The Platformer Splitter Reboiler shall be fitted with ULNBs (ARM 17.8.752).
7. The heat input rate for the Platformer Splitter Reboiler shall not exceed 39.9 MMBtu-HHV/hr (ARM 17.8.749).

E. Limitations on Wastewater System Components

1. All new drains associated with the benzene reduction project will be routed to the sewer system that is NSPS Subpart QQQ compliant and all such drains will be treated as subject to NSPS Subpart QQQ requirements (ARM 17.8.752).
2. All new junction boxes/vessels constructed as part of the benzene reduction project will be either water sealed, equipped with vent pipes meeting NSPS Subpart QQQ standards (applicable to new junction boxes), or equipped with closed vent systems and control devices that are designed and operated to meet the control requirements of NSPS Subpart QQQ (ARM 17.8.752).

F. Testing Requirements

The Platformer Splitter Reboiler (P-HTR-3) shall be tested every 5 years, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Sections XV.D.2 and 3 (ARM 17.8.105 and ARM 17.8.749).

G. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

CHS shall prepare and submit a quarterly emission report within 30 days of the end of each calendar quarter. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service). The quarterly report shall also include the following:

1. SO₂ emission data from the refinery fuel gas system continuous H₂S concentration monitor required by Section III. The SO₂ emission rates shall be reported for the following averaging periods:
 - a. Average lb/hr per calendar day
 - b. Total lb per calendar day
 - c. Total tons per month
2. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates.

3. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section XV.D.1 through 5.
4. Reasons for any emissions in excess of those specifically allowed in Section XV.D with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

Section XVI: Limitations and Conditions for Storage Tanks (Tanks 135-139, 142, 143 and Additive Tanks 1-4)

- A. CHS shall comply with all applicable standards and limitations, and the testing, monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable:
 1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
 2. Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984. This applies to Tanks 135-138, 142 and 143.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):
 1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tanks 135, 136, 137, 138, 142, and 143, which are classified as Group 1 storage vessels.
 3. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tank 139, which is classified as a Group 2 storage vessel.
- C. Limitations for Storage Tanks
 1. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 (2)).
 2. Storage Tanks 135 and 136 shall each be equipped with an external floating roof and submerged fill piping (ARM 17.8.752).

3. VOC emissions from Storage Tanks 137, 138, 142, and 143 shall be controlled by the installation and use of an internal floating roof and submerged fill piping (ARM 17.8.340, 40 CFR 60, Subpart Kb, and ARM 17.8.752).
4. Storage Tank 139 shall only store #1 or #2 diesel fuel and the VOC emissions from Storage Tank 139 shall be controlled by the installation and use of a fixed roof with pressure/vacuum vents and a submerged fill piping (ARM 17.8.749).
5. The total annual VOC emissions from the truck loading rack, VCU and associated equipment (which includes all associated storage tanks (135-139, 142, 143 and Additive Tanks # 1-4)), and any associated fugitives shall not exceed 39.23 TPY based on a rolling 12-calendar month total. This is total combined VOC emission limit for the applicable units listed in Section (XVI) and Section VI (ARM 17.8.749).
6. A monitoring and maintenance program, as described under 40 CFR Part 60 VVa, and meeting the requirements of 40 CFR Part 60 GGGa shall be instituted (ARM 17.8.752).

D. Monitoring Requirements

1. Combined VOC emissions from Storage Tanks 135-139, 142-143, and Additive tanks 1-4 shall be calculated and monitored utilizing AP42 calculation methods with key parameters of throughput and material properties. Tank emissions during periods the tank roofs are landed on its legs shall be calculated using appropriate AP-42 emissions equations (ARM 17.8.749).
2. CHS shall document, by month, the total VOC emissions from Storage Tanks 135-139, 142, 143; and Additive Tanks 1-4 and all associated fugitive sources. This must also include emissions while the roofs of the internal floating and external floating tanks are floating and emissions during time periods that the tank roofs are landed on the legs. This monthly information and the emissions relating to the operation of the new truck loading rack, VCU and all associated fugitive sources shall be used to verify compliance with the rolling 12-month limitations in Section(s) XVI.C.5 and VI.C.1.

E. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

CHS shall prepare and submit a quarterly emission report within 30 days of the end of each calendar quarter. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service). The quarterly report shall also include the applicable 12-month rolling total VOC emissions, by month, as required in XVI.C.5 and VI.C.1.

Section XVII: Limitations and Conditions for Storage Tank 133

- A. CHS shall comply with all applicable standards and limitations, and the testing, monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable:
 - 1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
 - 2. Subpart UU - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):
 - 1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 - 2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tank 133, which is classified as a Group 2 storage vessel.
- C. Except where 40 CFR 60, Subpart UU is applicable, CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 (2)).
- D. Limitations for Storage Tank 133
 - 1. VOC emissions from Storage Tank 133 shall not exceed 12.3 tons/rolling 12-calendar month total (ARM 17.8.749).
 - 2. Storage Tank 133 shall be a fixed roof tank with a pressure/vacuum vent and submerged fill piping. While in asphalt and gas oil service, the tank may be heated and may be operated without the pressure/vacuum vent (ARM 17.8.752).
 - 3. A monitoring and maintenance program, as described under 40 CFR 60, Subpart VVa, and meeting the requirements of 40 CFR 60, Subpart GGGa shall be instituted (ARM 17.8.752).
- E. Monitoring Requirements

VOC emissions from Storage Tank 133 shall be calculated and monitored utilizing AP42 calculation methods with key parameters of throughput and material properties (ARM 17.8.749).

- F. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)
1. CHS shall document, by month, the total VOC emissions from Tank 133. The monthly information shall be used to verify compliance with the rolling 12-month limitation in Section XVII.D.1. (ARM 17.8.749).
 2. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each calendar quarter. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service). The quarterly report shall also include the 12-month rolling total VOC emissions, by month, for Storage Tank 133.

Section XVIII: Wastewater Facilities

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable (ARM 17.8.340):
1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
 2. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater System, shall apply to, but not be limited to:
 - API Separator(s)
- B. Limitations for Wastewater Facilities
1. CHS shall equip, operate, and maintain the API Separators (TK-3437 and TK-3447) with a vapor collection system to collect and route emissions from the enclosed vapor space to a carbon adsorption system or thermal combustor to comply with 40 CFR 60 Subpart QQQ (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart QQQ).
 2. CHS shall equip, operate, and maintain the Dissolved Gas Flotation (DGF) Units (TK-3448 and TK-3458) with a vapor collection system to collect and route emissions from the enclosed vapor space to a carbon adsorption system or thermal combustor that meets the requirements of 40 CFR 60 Subpart QQQ. These two units are not subject to 40 CFR 60 Subpart QQQ (ARM 17.8.752).
- C. Monitoring Requirements
1. Whether a carbon adsorber is used for VOC emissions reduction or whether a thermal incinerator is used for VOC control, CHS shall comply with the appropriate monitoring as required by 40 CFR 60.695 (ARM 17.8.749 and 40 CFR Subpart QQQ).

2. CHS shall implement a Leak Detection and Repair (LDAR) program meeting 40 CFR 60 Subpart GGGa for all new components in VOC service installed as a part of the thermal combustor project system (ARM 17.8.752).

D. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

1. CHS shall keep records and furnish reports to the Department as required by 40 CFR 60, Subpart QQQ, for requirements not overridden by 40 CFR 63, Subpart CC.
2. CHS shall provide copies to the Department, upon the Department's request, of any records of testing results, monitoring operations, recordkeeping and report results as specified under 40 CFR 60, Subpart QQQ, Sections 60.693-2, 60.696, 60.697, and 60.698, for requirements not overridden by 40 CFR 63, Subpart CC.

Section XIX: Limitations and Conditions for Intermediate Storage Tanks 146 and 147

- A. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):
1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tank 146, which is classified as a Group 2 storage vessel.
- B. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 (2)).
- C. Limitations for Storage Tank 146 and Tank 147
1. Storage Tanks 146 and 147 shall be fixed roof tanks with submerged fill piping (ARM 17.8.752).
 2. Storage Tanks 146 and 147 shall store only intermediate products with a true vapor pressure less than 0.49 actual pounds per square inch (psia) (ARM 17.8.749).
 3. CHS shall comply with 40 CFR 63 Subpart CC as applicable to Tanks 146 and 147 (ARM 17.8.342 and 40 CFR 60 Subpart CC).
- D. Monitoring Requirements
- A monitoring and maintenance program, as described under 40 CFR 60, Subpart VVa, and meeting the requirements of 40 CFR 60, Subpart GGGa shall be instituted (ARM 17.8.752).

E. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749).

CHS shall calculate annual emissions from the operation of Tank 146 and Tank 147 and report these emissions with the annual emission inventory (ARM 17.8.749).

Section XX: Replacement Refinery Flare / Flare Gas Control System (Upon startup of the Replacement Refinery Flare)

A. Limitations and Standards:

1. The Replacement Refinery Flare shall have a minimum stack height of 199 feet from ground level with an allowance of 2 feet of deviation. The Replacement Refinery Flare shall be located as described in the MAQP #1821-33 application (ARM 17.8.749).
2. CHS shall comply with all applicable requirements of 40 CFR 63.670 and 40 CFR 63.671, including flare design, operation, and monitoring requirements (ARM 17.8.752; 40 CFR 63.670, 40 CFR 63.671, ARM 17.8.342). The Replacement Refinery Flare shall be steam assisted (ARM 17.8.749).
3. CHS shall not flare in the Replacement Refinery Flare any gas exceeding 162 ppmv H₂S determined hourly on a 3-hour average basis. The combustion of process upset gases, as defined in 40 CFR 60 Subpart Ja, or fuel gas as defined in 40 CFR 60 Subpart Ja that is released to the flare as a result of relief valve leakage or other emergency malfunctions, is exempt from this limit (ARM 17.8.752).
4. CHS shall comply with all applicable requirements of 40 CFR 60 Subpart Ja, including requirements for a flare management plan, root cause analysis program, flow monitoring, and total reduced sulfur or H₂S monitoring (ARM 17.8.340 and 40 CFR 60 Subpart Ja). The flare management plan shall specifically discuss the operation and monitoring of the flare water seal and identify the associated backpressure it provides, and discuss maximizing use of the flare gas treatment and recovery system during planned maintenance events on the flare gas recovery system (ARM 17.8.749 and ARM 17.8.752).
5. CHS shall install and operate a Flare Gas Treatment and Recovery System which shall include three (3) GARO AB 1500 compressors or equivalent, and amine treatment capacity to ensure treatment of captured vent gases to meet NSPS Ja requirements (ARM 17.8.749, ARM 17.8.752).
6. CHS shall implement a Leak Detection and Repair (LDAR) program meeting 40 CFR 60 Subpart GGGa for all new components in VOC service installed as a part of the Replacement Refinery Flare project, including components added to recover and treat flare gas from the Zone E flare (Coker flare) system (ARM 17.8.752).

B. Monitoring and Recordkeeping:

1. CHS shall maintain onsite, and available at all times, the as-built design specifications of the flare and flare gas treatment and recovery system, such that a demonstration of compliance with design standards of 40 CFR 63.670

and 40 CFR 63.671, the Flare Gas Treatment and Recovery System design requirements, and the stack height requirement can be made. The records shall include manufacturer/vendor data as applicable (ARM 17.8.749).

2. CHS shall comply with applicable recordkeeping requirements of 40 CFR 63.670 and 40 CFR 63.671 (40 CFR 63.670, 40 CFR 63.671 and ARM 17.8.342).
3. CHS shall monitor compliance with the 162 ppmv H₂S flare gas limitation of Section XX.A.6 in accordance with the monitoring requirements provided in 40 CFR 60 Subpart Ja (ARM 17.8.749).
4. CHS shall comply with the monitoring and recordkeeping requirements outlined in 40 CFR 60 Subpart VVa except where specifically exempted in 40 CFR 60 Subpart GGGa (ARM 17.8.749).

C. Reporting:

1. CHS shall comply with the applicable reporting requirements of 40 CFR 60 Subpart Ja (ARM 17.8.340 and 40 CFR 60 Subpart Ja).
2. CHS shall submit reports to the Department as outlined in the 40 CFR 60 Subpart VVa reporting requirements incorporated by reference into 40 CFR 60 Subpart GGGa (ARM 17.8.749).
3. CHS shall comply with applicable reporting requirements of 40 CFR 63.670 and 40 CFR 63.671 (40 CFR 63.670, 40 CFR 63.671 and ARM 17.8.342.)

Section XXI: Sour Water Stripper Ammonia Combustor

A. Limitations and Standards:

1. CHS shall install and operate Selective Catalytic Reduction technology on the Ammonia Combustor to achieve NO_x emissions of no more than 61 ppmv at 3% O₂ on a 365-day rolling average basis, as measured by NO_x CEMS and calculated on each calendar day basis, applicable at all times, including startup and shutdown (ARM 17.8.752).
2. CHS shall not emit more than 1.85 lb/hr of NO_x on a rolling 24-hr average basis from the Ammonia Combustor, as measured by NO_x CEMS and stack flowrate monitor with appropriate moisture correction defined by an initial source test. The initial source test shall be completed within 180 days of startup of the ammonia combustor. This limit shall not apply during startup and shutdown of the unit when the SCR is not at its design operating temperature (ARM 17.8.749).
3. Ammonia emissions from the Ammonia Combustor shall not exceed 10 ppmv at 3% O₂ (ARM 17.8.752).
4. CHS shall not emit from the Ammonia Combustor SO₂ in excess of the following, as measured by SO₂ CEMS (ARM 17.8.752):

- a. 20 ppmv on a dry basis, corrected to 0% excess air, determined hourly on a 3-hour rolling average basis, and;
 - b. SO₂ in excess of 8 ppmv on a dry basis, corrected to 0% excess air, determined daily on a 365-successive calendar day rolling average basis.
5. CHS shall not emit from the Ammonia Combustor SO₂ in excess of 0.80 lb/hr (ARM 17.8.749).
 6. CHS shall comply with all applicable requirements of 40 CFR 60 Subpart Ja (ARM 17.8.340 and 40 CFR 60 Subpart Ja).
 7. The Ammonia Combustor shall be operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours as determined by visual survey (ARM 17.8.752).

B. Monitoring and Recordkeeping:

1. CHS shall monitor compliance with the SO₂ emissions limitations of Section XXI.A.4 according to 40 CFR 60.8 and 40 CFR 60.104a, and 40 CFR 60.107a, and as otherwise described in 40 CFR 60 Subpart Ja. CHS shall comply with all applicable monitoring and recordkeeping requirements of 40 CFR 60 Subpart Ja (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja).
2. CHS shall perform source testing for NH₃ utilizing methodology as agreed in writing by CHS and the Department, on an every four year basis (ARM 17.8.749).

C. Reporting:

1. CHS shall submit the quarterly emission reports within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service). Report information shall include:
 - a. a summary of any excess emissions
 - b. reasons for any excess emissions with mitigative measures utilized and corrective action taken to prevent recurrence, and
 - c. compliance determinations with associated limits
2. CHS shall report SO₂ emissions in accord with 40 CFR 60 Subpart Ja. CHS shall comply with all applicable reporting requirements of 40 CFR 60 Subpart Ja (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja).

Section XXII: Crude Oil Blending Project – Tanks 153 and 1821-37B – 260,000 Barrel External Floating Roof Tanks

A. Limitations and Standards:

1. CHS shall meet the equipment design and work practice standards of 40 CFR 60 Subpart Kb, as applicable to Crude Oil Storage Tanks 153 and 1821-37B (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60 Subpart Kb).
2. CHS shall comply with the requirements of 40 CFR 63 Subpart CC and 40 CFR 60 Subpart Kb as applicable to Crude Oil Storage Tanks 153 and 1821-37B (ARM 17.8.340 and 40 CFR 60 Subpart Kb; ARM 17.8.342 and 40 CFR 63 Subpart CC).
3. CHS shall implement an LDAR program equivalent to 40 CFR 60 Subpart GGGa for the refinery equipment associated with Crude Oil Storage Tanks 153 and 1821-37B (ARM 17.8.752).

B. Monitoring, Recordkeeping, and Reporting:

1. CHS shall notify the Department of startup within 30 days of startup of Crude Oil Storage Tank 1821-37B, as determined by the earlier of postmark or email date (ARM 17.8.749).
2. CHS shall comply with all applicable testing, monitoring, recordkeeping, and reporting requirements of 40 CFR 60 Subpart Kb and 40 CFR 63 Subpart CC as applicable to Crude Oil Storage Tanks 153 and 1821-37B. (ARM 17.8.340 and 40 CFR 60 Subpart Kb, ARM 17.8.342 and 40 CFR 63 Subpart CC).

Section XXIII: Limitations and Conditions for Hydrogen Plant #3. (This equipment originated from MAQP #1821-36 originally titled as the Grassroots Hydrocracker Project since there is a multi-source limit that includes the FCCU regenerator).

A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable:

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
2. Subpart Ja - Standards of Performance for Petroleum Refineries applies to the Hydrogen Reformer Unit Heater (067HT0001)
3. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, applies to Hydrogen Plant #3. The compressors in Hydrogen Plant #3 are subject to Subpart GGGa when processing Refinery Fuel Gas (RFG) or other process gases. When the unit feed is natural gas, the compressors are not considered to be in VOC service."

4. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to Hydrogen Plant #3.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAP for Source Categories (ARM 17.8.342).
1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 2. Subpart CC - NESHAP from Petroleum Refineries shall apply to, applicable components in Hydrogen Plant #3 with the potential for greater than five percent weight HAP.
 3. Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters applies to the Hydrogen Reformer Unit Heater (067HT0001.)
- C. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 (2)).
- D. CHS shall not exceed 879,697 tons per year total CO₂e (rolling 12-month total) from the Hydrogen Reformer Heater (067HT0001), and the FCCU (ARM 17.8.479 and 17.8.752).
- E. Limitations on Individual Sources (ARM 17.8.752)
1. Hydrogen Reformer Heater (067HT0001)
 - a. SO₂ emissions from 067HT0001 shall not exceed (ARM 17.8.749 and 17.8.752):
 - i. 9.76 tons/12-month rolling total;
 - ii. 6.0 lb/hr based on a 3-hr rolling average.
 - b. CHS shall not burn any fuel gas that contains H₂S in excess of 162 ppmvd determined hourly on a 3-hour rolling average basis and H₂S in excess of 60 ppmvd determined daily on a 365-successive calendar day rolling average basis (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Ja).
 - c. The Hydrogen Reformer Heater (067HT0001) shall be equipped with low NO_x burners and selective catalytic reduction; and ammonia slip shall not exceed 10 ppm average ammonia demonstrated for performance tests (ARM 17.8.749 and 17.8.752).
 - d. NO_x emissions from the Hydrogen Reformer Heater (067HT0001) shall not exceed:

- i. 25.16 tons/rolling 12-calendar month total (ARM 17.8.749);
 - ii. 5.62 lb/hr 365-day rolling average including startup and shutdown based on NO_x CEMS (ARM 17.8.749 and 17.8.752);
 - iii. 22.5 lb/hr during periods of startup, on an hourly rolling 24-hour average basis. Startup begins when fuel is first fired and startup ends when the SCR inlet reaches its required temperature and ammonia injection has been established (ARM 17.8.749 and 17.8.752).
- e. CHS shall maintain documentation of the necessary catalyst operating temperature on-site for each type of catalyst used in the SCR (ARM 17.8.749).
- f. CO emissions from the Hydrogen Reformer Heater (067HT0001) shall not exceed:
- i. 91.08 tons/rolling 12-calendar month total (ARM 17.8.749);
 - ii. 20.8 lb/hr 365-day rolling average based on CO CEMS (ARM 17.8.749 and 17.8.752);
 - iii. 41.6 lb/hr during periods of startup, on an hourly rolling 36-hr average basis (ARM 17.8.749 and 17.8.752).
- g. VOC emissions from the Hydrogen Reformer Heater (067HT0001) shall not exceed 1.26 lb/hr based on EPA Reference Methods 18 and 25, or another methodology as agreed in writing between CHS and the Department (ARM 17.8.749 and ARM 17.8.752).
- h. PM₁₀/PM_{2.5} emissions from the Hydrogen Reformer Heater (067HT0001) shall not exceed 4.2 lb/hr based on EPA Reference Methods 5 or 201 and 202 (ARM 17.8.749 and 17.8.752).
- i. CO_{2e} emissions from the Hydrogen Reformer Heater (067HT0001) shall be minimized by:
- i. Firing only PSA tailgas, RFG or pipeline quality natural gas (ARM 17.8.749 and 17.8.752);
 - ii. Preventive tune-ups per 40 CFR 63 Subpart DDDDD (ARM 17.8.749, ARM 17.8.752 and 40 CFR 63 Subpart DDDDD).
- j. CO, VOC and PM/PM₁₀ emissions shall be controlled by proper design and good combustion practices (ARM 17.8.749 and 17.8.752).

F. Monitoring/Testing Requirements

- 1. CHS shall install, operate, calibrate, and maintain the following CEMS/CERMS on the Hydrogen Reformer Heater (067HT0001)

- a. NO_x (40 CFR 60, Subpart Ja)
 - b. O₂ (40 CFR 60, Subpart Ja)
 - c. H₂S on fuel gas systems (not individual heaters). This is not required if either natural gas or PSA tailgas are used as these fuels are exempt from Subpart Ja due to their characteristics (40 CFR 60, Subpart Ja).
 - d. Stack Flow Rate (ARM 17.8.749)
2. CHS shall install, operate, calibrate, and maintain a CO CEMS/CERMS for the Hydrogen Reformer Heater (067HT0001) (ARM 17.8.749).
 3. CHS shall perform source testing and/or demonstrate compliance for the Hydrogen Reformer Heater (067HT0001), for the pollutants listed below with the EPA reference methods and methodologies at the frequencies indicated:
 - a. NO_x – Every three years from the date of the last source test using EPA Method 7, in conjunction with annual CEMS/CERMS RATA performance testing in accordance with Appendix F (40 CFR Part 60) requirements, or according to another testing/ monitoring schedule as may be approved by the Department, for NO_x/O₂ and CO (EPA Method 10), concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits (ARM 17.8.105 and ARM 17.8.749, 40 CFR 60, Subpart Ja).
 - b. CO – Every three years from the date of the last source test using EPA Method 10. for CO in conjunction with the annual CEMS/CERMS RATA performance testing in accordance with Appendix F (40 CFR Part 60). (ARM 17.8.749).

VOC – EPA Method 18 and 25. EPA Method 18 and 25 or another methodology as agreed between CHS and the Department, as requested by the Department (ARM 7.8.749).

 - c. PM₁₀/PM_{2.5} – EPA Method 5 or 201 and 202. Once every 6 years or according to another testing/monitoring schedule as may be approved by the Department (ARM 7.8.749).
 - d. Ammonia Slip – The Hydrogen Reformer Heater shall be tested within two years of the initial source test and thereafter as requested by the Department to demonstrate compliance with the 10 ppm limit. The ammonia testing protocol shall be determined using a methodology as agreed in writing between CHS and the Department (ARM 17.8.749 and 17.8.752).
 - e. CO_{2e} Emissions – For the hydrogen reformer heater (067HT0001) compliance shall be demonstrated following the calculation procedures of 40 CFR part 98 subpart P. For the FCCU regenerator compliance

shall be demonstrated following the calculation procedures of 40 CFR part 98 subpart Y for catalytic cracking units (ARM 17.8.749 and ARM 17.8.752).

4. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts Ja, 60.100a-60.108a, and Appendix B, Performance Specifications 2, 3, 6, and Appendix F; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors (ARM 17.8.749).
5. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, and breakdowns and repairs of CEMS related equipment. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated (ARM 17.8.749).
6. Compliance with the opacity limitation listed in Section XXIII.C shall be determined using EPA Reference Method 9 testing by a qualified observer (ARM 17.8.749).

G. Recordkeeping and Reporting Requirements (ARM 17.8.749)

1. CHS shall document, by month, the total emissions from Hydrogen Reformer Heater (067HT0001). The monthly information shall be used to verify compliance with the rolling 12-month limitations within this permit.
2. CHS shall comply with the recordkeeping and reporting requirements including LDAR contained in 40 CFR 60, Subpart VVa (ARM 17.8.340 and 40 CFR 60 Subpart GGGa).
3. CHS shall submit quarterly emission reports to the Department based on data from the installed CEMS/CERMS. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service). Report information shall include:
 - a. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates (ARM 17.8.749).
 - b. Monitoring downtime that occurred during the reporting period (ARM 17.8.749).
 - c. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section XXIII.E (ARM 17.8.749).
 - d. Compliance determinations for permit limits in Section XXIII.E (ARM 17.8.749).

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

Section XXIV: Asphalt Storage Tanks under MAQP #1821-36 (These are the two new asphalt tanks and therefore are referenced under the permit action they were authorized under as Tank 152 and 1821-36_Aspphalt Tank B.)

- A. CHS shall comply with all applicable standards and limitations, and the testing, monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable:
 - 1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
 - 2. Subpart UU - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):
 - 1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 - 2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tanks 152 and 1821-36_Aspphalt Tank B, which are classified as Group 2 storage vessels.
- C. Within 60 days after achieving the maximum production rate at which the storage tank will operate but no later than 180 days after initial startup, CHS shall not discharge into the atmosphere from Tank 152 and 1821-36_Aspphalt Tank B exhaust gases with opacity greater than zero percent opacity except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for cleaning (40 CFR Part 60, Subpart UU, ARM 17.8.749 and ARM 17.8.340).
- D. Limitations for Asphalt Storage Tanks 152 and 1821-36_Aspphalt Tank B
 - 1. Storage Tanks 152 and 1821-36_Aspphalt Tank B shall be fixed roof tanks, utilize submerged fill piping and are permitted to operate with steam coils (ARM 17.8.752).
 - 2. A monitoring and maintenance program, as described under 40 CFR 60, Subpart VVa, and meeting the requirements of 40 CFR 60, Subpart GGGA shall be instituted (ARM 17.8.752).
- E. Monitoring and Reporting Requirements

VOC emissions from Storage Tanks 152 and 1821-36_Aspphalt Tank B shall be calculated and monitored utilizing the AP42 calculation methods (ARM 17.8.749).
- F. Notification Requirements (ARM 17.8.749)

CHS shall provide the Department written notification of startup of the asphalt tanks within 15 days of startup, as determined by the earlier of postmark or email date.

Section XXV: New Coker Charge Heater (H-7502), new #2 CU Vacuum Heater (005HT0002) and new Boiler #13 as part of the MUE Project. This section covers the two new heaters and the new boiler, applicable requirements and permit conditions which were permitted under MAQP #1821-43.

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable:
1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
 2. Subpart Db – Steam Generating Units applies to Boiler #13 for NO_x emissions.
 3. Subpart GGG -Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced after January 4, 1983, and on or Before November 7, 2006. The MUE Project does not result in additional applicability to subpart GGG. The #2 Crude Unit, DCU and NHT were already subject to subpart GGG requirements and is noted here for information purposes.
 4. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006. The MUE Project does not result in additional applicability to subpart GGGa. The MHC and RFG piping to the refinery steam generating boilers were already subject to the subpart GGGa requirements and is noted here for information purposes.
 5. Subpart Ja - Standards of Performance for Petroleum Refineries applies to the New Coker Charge Heater (H-7502), #2 CU Vacuum Heater and Boiler #13, as applicable. The Coker Charge Heater (H-7502) is subject to the process heater NO_x and fuel gas H₂S requirements. The #2 CU Vacuum Heater (05H0002) and Boiler #13 are subject to the fuel gas H₂S requirements.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAP for Source Categories (ARM 17.8.342).
1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 2. Subpart CC - NESHAP from Petroleum Refineries shall apply to affected sources or the collection of emission points as defined in this subpart.

3. Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters applies to the new Coker Charge Heater, new #2 CU Vacuum Heater and new Boiler #13).
- C. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 (2)).
- D. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, NSPS Subparts Ja and Db and Appendix B, Performance Specifications 2, 3, 6, and Appendix F; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors (ARM 17.8.749).
- E. Limitations on Individual Sources (ARM 17.8.752)
 1. New #2 CU Vacuum Heater (005HT0002)
 - a. CHS shall not burn any fuel gas that contains H₂S in excess of 162 ppmvd determined hourly on a 3-hour rolling average basis and H₂S in excess of 60 ppmvd determined daily on a 365-successive calendar day rolling average basis (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Ja).
 - b. The #2 CU Vacuum Heater (005HT0002) shall be equipped with ultra-low NO_x burners and NO_x emissions not exceed 1.05 lb/hr (ARM 17.8.749 and 17.8.752).
 - c. CO emissions from the #2 CU Vacuum Heater (005HT0002) shall be minimized by utilizing proper design and good combustion practices, and not exceed 1.05 lb/hr as demonstrated with EPA Federal Reference Method 10 (ARM 17.8.752).
 - d. VOC emission from the #2 CU Vacuum Heater (005HT0002) shall be minimized by utilizing proper design and good combustion practices, and shall be demonstrated by compliance with the CO emission limit and completion of the preventive tune-ups required per 40 CFR 63 Subpart DDDDD (ARM 17.8.749, ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).
 - e. CHS shall utilize proper design and good combustion practices and complete the preventative tune-ups required by 40 CFR 63 Subpart DDDDD to minimize PM₁₀/PM_{2.5} emissions at the #2 CU Vacuum Heater (005HT0002) . (ARM 17.8.749, ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).
 - f. CO_{2e} emissions from the #2 CU Vacuum Heater (005HT0002) shall be minimized by:
 - i. Firing only RFG or pipeline quality natural gas (ARM 17.8.749 and 17.8.752);

- ii. Completing preventive tune-ups per 40 CFR 63 Subpart DDDDD (ARM 17.8.749, ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).
- g. NO_x emissions from the #2 CU Vacuum Heater shall not exceed 4.59 tons per rolling 12-calendar month total;
- h. SO₂ emissions from the #2 CU Vacuum Heater shall not exceed 0.84 tons per rolling 12-calendar month total
- i. CO emissions from the #2 CU Vacuum Heater shall not exceed 4.59 tons per rolling 12-calendar month total

2. Coker Charge Heater (H-7502)

- a. CHS shall not burn any fuel gas that contains H₂S in excess of 162 ppmvd determined hourly on a 3-hour rolling average basis and H₂S in excess of 60 ppmvd determined daily on a 365-successive calendar day rolling average basis (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Ja).
- b. Coker Charge Heater (H-7502) shall be equipped with ultra-low NO_x burners and NO_x emissions not exceed 6.43/hr (365-day roll) (ARM 17.8.749, 17.8.752, ARM 17.8.340 and 40 CFR 60.107a(c))
- c. NO_x emissions from the Coker Charge Heater (H-7502) shall comply with either of the following two limits:
 - i. 40 ppmvd @ 0% O₂ determined daily on a 30-day rolling average basis (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60.102a(i));
 - ii. 0.040 lb/MMBtu (HHV) determined daily on a 30-day rolling average basis (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60.102a(i))

CHS may also choose to propose an alternate compliance demonstration (limit) because the Coker Charge Heater (H-7502) may be operated in turndown mode (as defined in 60.104a(i)(6)(ii)(c)) for extended periods of time. If no request is made, the above limits apply as indicated.

- d. CO emissions from the Coker Charge Heater (H-7502) shall utilize proper design and good combustion practices, and not exceed 6.43 lb/hr as demonstrated with EPA Federal Reference Method 10 (ARM 17.8.752).
- e. VOC emission from the Coker Charge Heater (H-7502) shall be minimized by utilizing proper design and good combustion practices, and shall be demonstrated by compliance with the CO emission limit and completion of the preventive tune-ups required by 40 CFR 63 Subpart

DDDDD (ARM 17.8.749, ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).

- f. CHS shall utilize proper design and good combustion practices and complete the preventative tune-ups required by 40 CFR 63 Subpart DDDDD to minimize PM₁₀/PM_{2.5} emissions at the Coker Charge Heater (H-7502) (ARM 17.8.749, ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).
- g. CO₂e emissions from the Coker Charge Heater (H-7502) shall be minimized by:
 - i. Firing only RFG or pipeline quality natural gas (ARM 17.8.749 and 17.8.752);
 - ii. Completing preventive tune-ups per 40 CFR 63 Subpart DDDDD (ARM 17.8.749, ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).
- h. NO_x emissions from the Coker Charge Heater (H-7502) shall not exceed 28.17 tons per rolling 12-calendar month total.
- i. SO₂ emissions from the Coker Charge Heater (H-7502) shall not exceed 5.92 tons per rolling 12-calendar month total.
- j. CO emissions from the Coker Charge Heater (H-7502) shall not exceed 28.17 tons per rolling 12-calendar month total.

3. Boiler #13

- a. CHS shall not burn any fuel gas that contains H₂S in excess of 162 ppmvd determined hourly on a 3-hour rolling average basis and H₂S in excess of 60 ppmvd determined daily on a 365-successive calendar day rolling average basis (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Ja).
- b. Boiler #13 shall be equipped with ultra-low NO_x burners and NO_x emissions not exceed 6.27/hr (365-day roll) (ARM 17.8.749, 17.8.752, ARM 17.8.340 and 40 CFR 60.40b).
- c. NO_x emissions from Boiler #13 shall not exceed 0.20 lb/MMBtu (HHV) heat input determined daily on a 30-day rolling average basis, applicable at all times, including periods of startup, shutdown and malfunction. CEMS shall be used for compliance demonstration (ARM 17.8.749 and 40 CFR 60, Subpart Db)
- d. CO emissions from Boiler #13 shall be minimized by utilizing proper design and good combustion practices, and not exceed 8.36 lb/hr as demonstrated with EPA Federal Reference Method 10 (ARM 17.8.749 and 17.8.752);

- e. VOC emission from Boiler #13 shall be minimized by utilizing proper design and good combustion practices, and shall be demonstrated by compliance with the CO emission limit and the completion of the preventive tune-ups required by 40 CFR 63 Subpart DDDDD (ARM 17.8.749, ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).
- f. CHS shall utilize proper design and good combustion practices and complete the preventative tune-ups required by 40 CFR 63 Subpart DDDDD to minimize PM₁₀/PM_{2.5} emissions at Boiler 13 (ARM 17.8.749, ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).
- g. CO_{2e} emissions from Boiler #13 shall be minimized by:
 - i. Firing only RFG or pipeline quality natural gas (ARM 17.8.749 and 17.8.752);
 - ii. Completing preventive tune-ups per 40 CFR 63 Subpart DDDDD (ARM 17.8.749, ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).
- h. NO_x emissions from Boiler #13 shall not exceed 27.47 tons per rolling 12-calendar month total.
- i. SO₂ emissions from Boiler #13 shall not exceed 6.72 tons per rolling 12-calendar month total.
- j. CO emissions from Boiler #13 shall not exceed 36.63 tons per rolling 12-calendar month total.

F. #2 CU Vacuum Heater Monitoring/Testing Requirements

- 1. Compliance for the #2 CU Vacuum Heater H₂S limit in Section XXV.E.1.a shall be demonstrated using a CEMS on the fuel gas supply unless exempted by 40 CFR 60.107(a)(3) (ARM 17.8.106, ARM 17.8.340 and 40 CFR 60 Subpart Ja).
- 2. Compliance for the #2 CU Vacuum Heater NO_x limit in Section XXV.E.1.b shall be demonstrated using Federal Reference Method 7E. Initial testing shall be conducted within 180 days of startup, concurrently with CO testing, and every 3 years thereafter or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.749 and ARM 17.8.106).
- 3. Compliance for the #2 CU Vacuum Heater CO limit in Section XXV.E.1.c shall be demonstrated using Federal Reference Method 10. Initial testing shall be conducted within 180 days of startup, concurrently with NO_x testing, and every 3 years thereafter using the date of the last source test or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.749 and ARM 17.8.106).
- 4. Compliance for the #2 CU Vacuum Heater VOC condition in Section XXV.E.1.d shall be demonstrated by compliance with the CO limit and the

recordkeeping required by 40 CFR 63 Subpart DDDDD (ARM 17.8.752, ARM 17.8.106 and 40 CFR 63 Subpart DDDDD).

5. Compliance for the #2 CU Vacuum Heater PM₁₀/PM_{2.5} condition in Section XXV.E.1.e shall be demonstrated via the recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.752, ARM 17.8.106, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).
6. Compliance for the #2 CU Vacuum Heater CO_{2e} condition in Section XXV.E.1.f shall be demonstrated via the recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).

G. Coker Charge Heater Monitoring/Testing Requirements

1. Compliance for the Coker Charge Heater H₂S limit in Section XXV.E.2.a shall be demonstrated using a CEMS on the fuel gas supply unless exempted by 40 CFR 60.107(a)(3) (ARM 17.8.752, ARM 17.8.106, ARM 17.8.340 and 40 CFR 60 Subpart Ja).
2. Compliance for the Coker Charge Heater NO_x limit in Section XXV.E.2.b shall be demonstrated using a NO_x CEMS and stack flow monitor (ARM 17.8.752, ARM 17.8.106, ARM 17.8.340 and 40 CFR 60 Subpart Ja).
3. Compliance for the Coker Charge Heater NO_x limit in Section XXV.E.2.c shall be demonstrated using NO_x and O₂ CEMS (ARM 17.8.752, ARM 17.8.106, ARM 17.8.340 and 40 CFR 60 Subpart Ja).
4. Compliance for the Coker Charge Heater CO limit in Section XXV.E.2.d shall be demonstrated by using Federal Reference Method 10. Initial testing shall be conducted within 180 days of startup, and every 3 years thereafter using the date of the last source test or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.752 and ARM 17.8.106).
5. Compliance for the Coker Charge Heater VOC limit in Section XXV.E.2.e shall be demonstrated by compliance with the CO limit and the recordkeeping required by 40 CFR 63 Subpart DDDDD (ARM 17.8.752, ARM 17.8.106 and 40 CFR 63 Subpart DDDDD).
6. Compliance for the Coker Charge Heater PM₁₀/PM_{2.5} condition in Section XXV.E.2.f shall be demonstrated via the recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 DDDDD).
7. Compliance for the Coker Charge Heater CO_{2e} condition in Section XXV.E.2.g shall be demonstrated via the recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 DDDDD).

H. Boiler #13 Monitoring/Testing Requirements

1. Compliance for Boiler #13 H₂S limit in Section XXV.E.3.a shall be demonstrated using a CEMs on the fuel gas supply unless exempted by 40 CFR 60.107(a)(3) (ARM 17.8.749, ARM 17.8.106, ARM 17.8.340 and 40 CFR 60 Subpart Ja).
2. Compliance for Boiler #13 NO_x limit in Section XXV.E.3.b shall be demonstrated using a CEMS and stack flow monitor (ARM 17.8.749, ARM 17.8.106, ARM 17.8.340 and 40 CFR 60 Subpart Ja).
3. Compliance for Boiler #13 NO_x limit in Section XXV.E.3.c shall be demonstrated using a NO_x and O₂ CEMs (ARM 17.8.749, ARM 17.8.106, ARM 17.8.340 and 40 CFR 60 Subpart Ja).
4. Compliance for Boiler #13 CO limit in Section XXV.E.3.d shall be demonstrated by compliance with Federal Reference Method 10. Initial testing shall be conducted within 180 days of startup, and every 3 years thereafter using the date of the last source test or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.752, 17.8.106, ARM 17.8.340 and 40 CFR 60 Subpart Ja).
5. Compliance for Boiler #13 VOC limit in Section XXV.E.3.e shall be demonstrated thru compliance with the CO limit and the recordkeeping required by 40 CFR 63 Subpart DDDDD (ARM 17.8.749, ARM 17.8.106, ARM 17.8.752 and 40 CFR 63 Subpart DDDDD).
6. Compliance for the Boiler #13 PM₁₀/PM_{2.5} condition in Section XXV.E.3.f shall be demonstrated via the recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.752, ARM 17.8.106 and 40 CFR 63 Subpart DDDDD).
7. Compliance for the Boiler #13 CO_{2e} condition in Section XXV.E.3.g shall be demonstrated via the recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.752 and 40 CFR 63 DDDDD).

I. LDAR Program for Equipment Leaks - #2 Crude Unit, DCU and NHT

CHS shall develop an effective LDAR program meeting the requirements of NSPS subpart GGGa for the #2 Crude Unit, DCU and NHT process units (ARM 17.8.752).

J. Recordkeeping and Reporting Requirements

1. CHS shall document, by month, the total emissions from the new equipment as part of the MUE Project. The monthly information shall be used to verify compliance with the rolling 12-month limitations in Section XXV. E.4 (ARM 17.8.749).
2. CHS shall submit quarterly emission reports to the Department based on data from the installed CEMS/CERMS. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address or up-loaded to the State of Montana's File Transfer Service using the Air Quality Bureau's

Administrative email address as the recipient (or equivalent service). Report information shall include:

- a. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates (ARM 17.8.749).
- b. Monitoring downtime that occurred during the reporting period (ARM 17.8.749).
- c. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section XXV.E (ARM 17.8.749).
- d. Reasons for any emissions in excess of those specifically allowed in Section XXV.E with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation (ARM 17.8.749).

K. Notification Requirements

CHS shall notify the Department within 30 days of startup of each of the following units: #2 CU Vacuum Heater, Coker Charge Heater, and Boiler #13 as determined by the earlier of the postmark date or email sent date (ARM 17.8.749).

Section XXVI: General Conditions

- A. Inspection - CHS 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), 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 all the terms, conditions, and matters stated herein shall be deemed accepted if CHS fails to appeal as indicated below.
- C. Compliance with Statutes and Regulations - Nothing in this permit shall be construed as relieving CHS of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq.* (ARM 17.8.756).
- D. Enforcement - Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties, or other enforcement as specified in Section 75-2-401 *et seq.*, MCA.
- E. Appeals - Any person or persons jointly or severally adversely affected by 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 Department personnel at the location of the permitted source.
- G. Duration of Permit - Construction or installation must begin or contractual obligations entered into that would constitute substantial loss within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall expire (ARM 17.8.762).
- H. Permit Fees - Pursuant to Section 75-2-220, MCA, as amended by the 1991 Legislature, failure to pay the annual operation fee by CHS may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

ATTACHMENT A

Refinery Limitations and Conditions associated with MAQP #1821-05 Compliance Determination

1. Gas fired external combustion
 - a. SO₂
 - i. Calculation Basis: AP-42 Section 1-4 (7/98 revision) and complete conversion of fuel gas H₂S to SO₂.
 - ii. Key Parameters: Monthly fuel use (scf) per combustion unit and refinery fuel gas H₂S content from CEMS.
 - b. NO_x, CO, PM₁₀/PM, VOC
 - i. Calculation Basis: AP-42 Section 1-4 (7/98 revision).
 - ii. Key Parameters: Monthly fuel use (scf) per combustion unit and monthly average fuel gas heat content.
2. CHS is no longer combusting fuel oil so this condition no longer applies but is being left in place as it was established as part of MAQP #1821-05. References to fuel oil combustion were removed from the permit as part of MAQP #1821-41.
 - a. SO₂
 - i. Calculation Basis: Methodology required in the Billings-Laurel SO₂ SIP and Appendix G of the CHS Consent Decree.
 - ii. Key Parameters: Sulfur content and specific gravity of alkylation unit polymer pursuant to Appendix G of the CHS Consent Decree.
3. Gas fired internal combustion
 - a. SO₂
 - i. Calculation Basis: AP-42 Section 1-4 (7/98 revision) and complete conversion of fuel gas H₂S to SO₂.
 - ii. Key Parameters: Monthly fuel use (scf) per combustion unit and fuel gas H₂S and Sulfur content.
 - b. NO_x, CO
 - i. Calculation Basis: AP-42 Section 3-2 (10/96 revision).
 - ii. Key Parameters: Monthly fuel use (scf) per combustion unit and monthly average fuel gas heat content.

c. PM₁₀/PM: Not applicable – not a significant source.

d. VOC

Calculation Basis: AP-42 Section 3-2 (10/96 revision)

Key Parameters: Monthly fuel use (scf) per combustion unit and monthly average fuel gas heat content.

4. Zone D (H-101, H-201 and H-202)

a. SO₂: Calculation Basis: CEMS data and methodology required in the Billings/Laurel SO₂ SIP

b. NO_x

i. Calculation Basis: NO_x and O₂ CEMS, Emission factors based on annual stack tests.

ii. Key Parameters: NO_x stack tests, monthly fuel use (scf) per combustion unit.

c. CO

i. Calculation Basis: CO and O₂ CEMS, Emission factors based on annual stack tests.

ii. Key Parameters: CO stack tests, monthly fuel use (scf) per combustion unit.

d. PM₁₀/PM

i. Calculation Basis: AP-42 Section 1-4 (7/98 revision).

ii. Key Parameters: Monthly fuel use (scf) per combustion unit and monthly average fuel gas heat content.

e. VOC

i. Calculation Basis: Emission factors based on annual stack tests for sources burning refinery fuel gas. For sources firing only natural gas, the most current VOC stack test will be used to develop emission factors.

ii. Key Parameters: VOC stack test.

5. Fugitive equipment leaks

a. SO₂, NO_x, CO, PM₁₀/PM: Not applicable

b. VOC

- i. Calculation Basis: EPA factors and NSPS and MACT control efficiencies (EPA-453/R-95-017).
 - ii. Key Parameters: Component counts by type and service.
- 6. Boiler #10
 - a. SO₂
 - i. Calculation Basis: Complete conversion of fuel gas H₂S to SO₂.
 - ii. Key Parameters: Monthly fuel use (scf) per combustion unit and refinery fuel gas H₂S content from CEMS.
 - b. NO_x
 - i. Calculation Basis: NO_x and O₂ CEMS, Volumetric stack flow rate monitor, Emission factors based on stack tests.
 - ii. Key Parameters: NO_x and O₂ CEMS, Reference Method 19, NO_x stack tests, monthly fuel use (scf), volumetric stack flow rate.
 - c. CO
 - i. Calculation Basis: CO and O₂ CEMS, Emission factors based on stack tests.
 - ii. Key Parameters: CO stack tests, monthly fuel use (scf).
 - d. PM₁₀/PM
 - i. Calculation Basis: AP-42 Section 1-4 (7/98 revision).
 - ii. Key Parameters: Monthly fuel use (scf) and monthly average fuel gas heat content.
 - e. VOC
 - i. Calculation Basis: Emission factors based on stack tests.
 - ii. Key Parameters: VOC stack tests, monthly fuel use (scf).
- 7. FCCU
 - a. SO₂

Calculation Basis: CEMS data and methodology required in CHS Consent Decree, NSPS Subpart J, and the Billings/Laurel SO₂ SIP.

b. NO_x

Calculation Basis: CEMS data and methodology required in CHS Consent Decree, NSPS Subpart J, and FCCU Regenerator flue gas flow rate.

c. CO

Calculation Basis: CEMS data and methodology required in CHS Consent Decree and NSPS Subpart Ja, and FCCU Regenerator flue gas flow rate.

d. PM₁₀/PM

i. Calculation Basis: Annual stack test results.

ii. Key Parameters: Monthly FCC charge rate (bbl).

e. VOC

i. Calculation Basis: AP-42 Section 5.1 (1/95 revision) and assumed 98% control efficiency.

ii. Key Parameters: Monthly FCC charge rate (bbl).

8. Zone A SRU Incinerator

a. SO₂: Calculation Basis: CEMS data and methodology required in Billings/Laurel SO₂ SIP

b. NO_x

i. Calculation Basis: Emission factors based on every 5-year stack tests.

ii. Key Parameters: Every 5-year NO_x stack test, monthly fuel use (scf).

c. CO, PM₁₀/PM, VOC

i. Calculation Basis: AP-42 Section 1-4 (7/98 revision).

ii. Key Parameters: Monthly fuel use (scf) and average fuel gas heat content.

9. Zone D SRU Incinerator

a. SO₂: Calculation Basis: CEMS data and methodology required in Billings/Laurel SO₂ SIP

b. NO_x

i. Calculation Basis: Emission factors based on annual stack tests.

ii. Key Parameters: Annual NO_x stack test, monthly fuel use (scf).

- c. CO, PM₁₀/PM, VOC: Not applicable – not a significant source
- 10. Wastewater
 - a. SO₂, NO_x, CO, PM₁₀/PM: Not applicable – not a source
 - b. VOC
 - i. Calculation Basis: AP-42, Table 5.1-2 (1/95 rev.).
 - ii. Key Parameters: Monthly wastewater flow (gal) from Lab Information Management System (LIMS).
- 11. Cooling towers
 - a. SO₂, NO_x, CO: Not applicable – not a source
 - b. PM₁₀/PM: Cooling tower design (Delayed coker unit cooling tower applicable)
 - c. VOC
 - i. Calculation Basis: AP-42, Section 5.1 (1/95 rev.).
 - ii. Key Parameters: Monthly cooling tower circulation (gal).
- 12. Loading facilities
 - a. SO₂: Not applicable – not a source
 - b. NO_x
 - i. Calculation Basis: VCU stack tests for lb NO_x/gal loaded.
 - ii. Key Parameters: Monthly volume of materials loaded from yield accounting.
 - c. CO
 - i. Calculation Basis: VCU stack tests for lb CO/gal loaded.
 - ii. Key Parameters: Monthly volume of materials loaded from yield accounting.
 - d. PM₁₀/PM: Not applicable – not a significant source
 - e. VOC
 - i. Calculation Basis: AP-42, Section 5.2-4 (1/95 rev.) and VCU stack tests for lb VOC/gal loaded.

- ii. Key Parameters: Monthly volume of material throughput from yield accounting, material property data (VP, MW, etc.).
- 13. Storage tanks
 - a. SO₂, NO_x, CO, PM₁₀/PM: Not applicable – not a source
 - b. VOC
 - i. Calculation Basis: actual emission, AP-42 calculation methods and other reasonable sources as outlined in the application for MAQP #1821-27.
 - ii. Key Parameters: Monthly volume of material throughput from yield accounting, material property data (VP, MW, etc.).

Montana Air Quality Permit (MAQP) Analysis
CHS Inc. – Laurel Refinery
MAQP #1821-43

I. Introduction/Process Description

A. Site Location/Description

The CHS Inc. (CHS) Laurel Refinery is a petroleum refinery located in the South ½ of Section 16, Range 24 East, Township 2 South, in Yellowstone County. A complete list of permitted equipment is available in the permit. The source categories for the refinery limitations and conditions associated with MAQP #1821-05 are listed below.

With the issuance of MAQP #1821-05, CHS requested to place enforceable limits on future ‘site-wide’ emissions for the collective units that were in operation at the facility at this time. Although modifications (including removal and addition of various emitting units) have occurred at the facility since these limitations were put in place, the following collective units identified at the time of issuance of MAQP #1821-05 continue to be subject to the limitations and conditions within the permit:

1. Gas-fired external combustion source type, includes:
 - a. #1 crude heater, crude preheater, #1 crude vacuum heater
 - b. #2 crude heater, #2 crude vacuum heater
 - c. Alkylation Unit hot oil belt heater
 - d. Platformer Heater (P-HTR-1), platformer debutanizer heater
 - e. Fluid Catalytic Cracking (FCC) Charge Heater (FCC-Heater-1) (Replaced with FCC-Charge Heater (FCC-Heater NEW)
 - f. NHT Reboiler Heater #1 (H-8302), NHT Reboiler Heater #2 (H-8303), and NHT Splitter Reboiler (H-8304), #2 NU Heater (shutdown as part of MAQP #1821-13), MDU Stripper Heater (Shutdown as a part of MAQP #1821-09 and modified and re-permitted as part of MAQP #1821-13, Currently Naphtha Hydrotreater (NHT) Charge Heater (H-8301)), PDA Heater (Shutdown as a part of MAQP #1821-13)
 - g. Zone D Hydrogen Plant Reformer Heater (H-101), Reactor Charge Heater (H-201), Fractionator Feed Heater (H-202)
 - h. Asphalt Loading Heater #1
 - i. #1 fuel oil heater, #60 tank heater
 - j. Boiler #9, Boiler #10, Boiler #11, and Boiler #12 (Boilers #11 and #12 were replacement boilers following shutdown and removal of #3, #4, and #5 boilers)

2. Fuel oil-fired external combustion sources, includes: #3 boiler (Shutdown and removed as part of MAQP #1821-15), #4 boiler (Shutdown and removed as part of MAQP #1821-22), #5 boiler (#5 boiler shutdown and removed as part of MAQP #1821-22), CO Boiler (Shutdown and removed as part of MAQP #1821-15);
3. Gas-fired internal combustion source, includes: Platformer recycle turbine, Zone D compressor gas engine (C-201B) (Shutdown as part of MAQP #1821-23), #1-4 unifier compressors (Shutdown with ULSD and coker projects);
4. FCC unit (FCCU) Regenerator;
5. Zone A Sulfur Recovery Unit (SRU) Tail Gas Incinerator (TGI, SRU-AUX-4);
6. Zone D SRU Incinerator;
7. Delayed Coker Unit: Zone E SRU/Tail Gas Incinerator Treatment Unit (TGTU)/TGI;
8. Fugitive equipment leaks include all equipment, as defined in 40 Code of Federal Regulations (CFR) 60, Subpart VV, in hydrocarbon service;
9. Wastewater facilities;
10. Cooling tower sources: #1 cooling tower (CT), #2 CT, #3 CT, and #5 CT;
11. Loading facilities: light product truck rack and vapor combustion unit (VCU), heavy oil truck rack, and heavy oil rail rack; and
12. Storage tanks: tank numbers 2, 7, 9 (Replaced with Tank 127), 12, 28 (Replaced with Tank 126), 41, 47, 56, 60, 61, 62, 63, 65 (Replaced with Tank 144), 66, 67 (Replaced with Tank 145), 68, 70, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 85, 86, 88, 91, 92, 93, 94, 95, 96, 100, 101, 102, 103, 104, 108, 109, 110, 111, 112, 113, 114, 117, 118, 120, 121, 122, 123, 126 (Replaced Tank 28), 127 (Replaced Tank 9), B-1, B-2, B-7, firetk 2, firetk 3, and firetk 4.

B. Permit History

On May 11, 1992, Cenex Harvest States Cooperatives (Cenex) was issued **MAQP #1821-01** for the construction and operation of a hydro-treating process to desulfurize FCC Unit feedstocks. The existing refinery property lies immediately south of the City of Laurel and about 13 miles southwest of Billings, Montana. The new equipment for the desulfurization complex is located near the western boundary of the existing refining facilities.

The hydrodesulfurization (HDS) process is utilized to pretreat Fluid Catalytic Cracking Unit (FCCU) feeds by removing metal, nitrogen, and sulfur compounds from these feeds. The proposed HDS unit also improved the quality of refinery finished products including gasoline, kerosene, and diesel fuel. The HDS project significantly improved the finished product quality by reducing the overall sulfur

contents of liquid products from the Cenex Refinery. The HDS unit provided low sulfur gas-oil feedstocks for the FCCU, which resulted in major reductions of sulfur oxide emissions to the atmosphere. However, only a minor quantity of the proposed sulfur dioxide (SO₂) emission reductions was made federally enforceable.

The application was not subject to the New Source Review (NSR) program for either nonattainment or Prevention of Significant Deterioration (PSD) since Cenex chose to "net out of major modification review" for the affected pollutants due to contemporaneous emission reductions at an existing emission unit.

The application was deemed complete on March 24, 1992. Additional information was received on April 16, 1992, in which Cenex proposed new short-term emission rates based upon modeled air quality impacts.

The basis for the permit application was due to a net contemporaneous emissions increase that was less than the significant level of 40 tons per year (TPY) for SO₂ and nitrogen oxides (NO_x). The application referred to significant SO₂ emission reductions, which were expected by addition of the HDS project. These anticipated major SO₂ reductions were not committed to by Cenex under federally enforceable permit conditions and limitations. The contemporaneous emissions decrease for SO₂ and NO_x, which were made federally enforceable under this permitting action, amount to approximately 15.5 and 23.7 tons per year, respectively.

Construction of the HDS/sulfur recovery complex was completed in December 1993 and the 180-day-shakedown period ended in June 1994.

MAQP #1821-02 was issued on February 1, 1997, to authorize the installation of an additional boiler (Boiler #10) to provide steam for the facility. Cenex submitted the original permit application for a 182.50-million British thermal units per hr (MMBtu/hr) boiler on February 9, 1996. This size boiler is a New Source Performance Standard (NSPS) affected facility and the requirements of NSPS Subpart Db would have applied to the boiler. On November 15, 1996, Cenex submitted a revised permit application proposing a smaller boiler (99.90 MMBtu/hr). The manufacturer of the proposed boiler has not been identified; however, the boiler is to be rated at approximately 80,000 lbs steam/hour with a heat input of 99.9 MMBtu/hour. The boiler shall have a minimum stack height of 75 feet above ground level. The boiler will be fired on natural gas until November 1, 1997, at which time Cenex will be allowed to fire refinery fuel gas in the boiler. The requirements of NSPS Subpart Dc apply to the boiler. The requirements of NSPS Subpart J and GGG will also apply as of November 1, 1997. Increases in emissions from the new boiler are detailed in the permit analysis for MAQP #1821-02. Modeling performed has shown that the emission increase will not result in a significant impact to the ambient air quality.

Cenex has also requested a permit alteration to remove the SO₂ emission limits for the C-201B compressor engine because the permit already limits C-201B to be fired on either natural gas or unodorized propane. Cenex also requested that if the SO₂ emission limits could not be removed, the limits should be corrected to allow for the combustion of natural gas and propane. The Department of Environmental Quality (Department) has altered the permit to allow for burning odorized propane in the C-201B compressor.

Cenex also requested a permit modification to change the method of determining compliance with the HDS Complex emitting units. MAQP #1821-01 requires that compliance with the hourly (lb/hr) emission limits be determined through annual source testing and that the daily (lb/day), annual (ton/yr), and Administrative Rules of Montana (ARM) 17.8 Subchapter 8 requirements (i.e., PSD significant levels and review) be determined by using actual fuel burning rates and the manufacturer's guaranteed emission factors listed in Attachment B. Cenex has requested to use actual fuel burning rates and fixed emission factors determined from previous source test data in order to determine compliance with the daily (lb/day) and annual (ton/yr) emission limits. The Department agrees that actual stack testing data is preferred to manufacturer's data for the development of emission factors. However, the Department is requiring that the emission factor be developed from the most recent source test and not on an average of previous source tests. The permit has been changed to remove Attachment B and rely on emission factors derived from the most recent source test, along with actual fuel flow rates for compliance determinations. However, in order to determine compliance with ARM 17.8 Subchapter 8, Cenex shall continue to monitor the fuel gas flow rates in both scf/hr and scf/year.

On June 4, 1997, Cenex was issued **MAQP #1821-03** to modify emissions and operational limitations on components in the Hydrodesulfurization Complex at the Laurel refinery. The unit was originally permitted in 1992, but has not been able to operate adequately under the emissions and operational limitations originally proposed by Cenex and permitted by the Department. This permitting action corrected these limitations and conditions. The new limitations established by this permitting action were based on operational experience and source testing at the facility and the application of Best Available Control Technology (BACT).

The following emission limitations were modified by this permit.

Source	Pollutant	Previous Limit	New Limit
SRU Incinerator stack (E-407 & INC-401)	SO ₂	291.36 lb/day	341.04 lb/day
	NO _x	2.1 ton/yr 11.52 lb/day 0.48 lb/hr	3.5 ton/yr 19.2 lb/day 0.8 lb/hr
Compressor (C201-B)	NO _x	18.42 ton/yr	30.42 ton/yr
		6.26 lb/hr	7.14 lb/hr
	CO	16.45 ton/yr	68.6 ton/yr
		5.15 lb/hr - when on natural gas	6.4 lb/hr - when on natural gas
Fractionator Feed Heater (H-202)	SO ₂	0.53 ton/yr	4.93 ton/yr
		0.135 lb/hr	1.24 lb/hr
	NO _x	6.26 ton/yr	8.34 ton/yr
		1.43 lb/hr	2.09 lb/hr
	CO	3.29 ton/yr	6.42 ton/yr
		1.00 lb/hr	1.61 lb/hr
	VOC	0.26 ton/yr	0.51 ton/yr
	SO ₂	0.214 lb/hr	1.716 lb/hr

Source	Pollutant	Previous Limit	New Limit
Reactor Charge Heater (H-201)		0.79 ton/yr	6.83 ton/yr
	NO _x	9.24 ton/yr	11.56 ton/yr
		2.11 lb/hr	2.90 lb/hr
	CO	4.86 ton/yr	8.89 ton/yr
		1.40 lb/hr	2.23 lb/hr
	VOC	0.39 ton/yr	0.71 ton/yr
Reformer Heater (H-101)	SO ₂	0.128 lb/hr	2.15 lb/hr
		0.48 ton/yr	3.35 ton/yr
	NO _x	6.16 lb/hr	6.78 lb/hr
	VOC	0.24 ton/yr	0.35 ton/yr
Old Sour Water Stripper	SO ₂	304.2 ton/yr	290.9 ton/yr
	NO _x	125.7 ton/yr	107.9 ton/yr

Emission limitations in this permit are based on the revised heat input capacities for units within the HDS. The following changes were made to the operational requirements of the facility.

Unit	Originally Permitted Capacity	New Capacity
SRU Incinerator stack (E-407 & INC-401)	4.8 MMBtu/hr	8.05 MMBtu/hr
Compressor (C201-B)	1600 hp (short term) 1067 hp (annual average)	1800 hp (short term and annual average)
Fractionator Feed Heater (H-202)	27.2 MMBtu/hr (short term) 20.4 MMBtu/hr (annual avg.)	29.9 MMBtu/hr (short term) 27.2 MMBtu/hr (annual avg.)
Reactor Charge Heater (H-201)	37.7 MMBtu/hr (short term) 30.2 MMBtu/hr (annual avg.)	41.5 MMBtu/hr (short term) 37.7 MMBtu/hr (annual avg.)
Reformer Heater (H-101)	123.2 MMBtu/hr (short term and annual avg.)	135.5 MMBtu/hr (short term) 123.2 MMBtu/hr (annual avg.)

It has been determined that the emission and operational rates proposed during the original permitting of the HDS unit were incorrect and should have been at the levels Cenex is now proposing. Because of this, the current action and the original permitting of the HDS must be considered one project in order to determine the permitting requirements. When combined with the original permitting of the HDS, the emission increases of NO_x and SO₂ would exceed significant levels and subject this action to the requirements of the NSR/PSD program. During the original permitting of the HDS complex, Cenex chose to “net out” of NSR and PSD review by accepting limitations on the emissions of NO_x and SO₂ from the old SWS. Because of the emission increases proposed in this permitting action, additional emission reductions must occur. Cenex has proposed additional reductions in emissions from the old SWS to offset the increases allowed by this permitting action. These limitations will reduce the “net emission increase” to less than significant levels and negate the need for review under the NSR/PSD program.

The new emission limits for SO₂ and NO_x from the old SWS are 290.9 and 107.9 tons per year, respectively.

This permitting action also removes the emission limits and testing requirements for particulate matter with an aerodynamic diameter of 10 microns or less (PM₁₀) on the HDS heaters (H-101, H-201, and H-202). These heaters combust refinery gas, natural gas, and PSA gas. The Department has determined that potential PM₁₀ emissions from these fuels are minor and that emission limits and the subsequent compliance demonstrations for this pollutant are unnecessary.

Also removed from this permit are the compliance demonstration requirements for SO₂ and Volatile Organic Compounds (VOC) when the combustion units are firing natural gas. The Department has determined that firing the units solely on natural gas will, in itself, demonstrate compliance with the applicable limits.

This action will result in an increase in allowable emissions of VOC and Carbon Monoxide (CO) by 4.7 tons per year and 60 tons per year, respectively. Because of the offsets provided by reducing emissions from the old SWS, this permitting action will not increase allowable emissions of SO₂ or NO_x from the facility.

The following changes have been made to the Department's preliminary determination (PD) in response to comments from Cenex.

The emission limits for the old SWS have been revised to ensure that the required offsets are provided without putting Cenex in a non-compliance situation at issuance of the permit. The compliance determinations and the reporting requirements were also changed to reflect this requirement.

The CO emission limits for H-201 have been revised; the old limits were inadvertently left in the PD. The table included in the analysis has also been revised to reflect this change.

Section III.E.2 was changed to clarify that the firing of natural gas would show compliance with the VOC emission limits for Boiler #10.

Section F. of the General Conditions was removed because the Department has placed the applicable requirements from the permit application into the permit.

Numbering has been changed in Section III.

MAQP #1821-04 was issued to Cenex on March 6, 1998, in order to comply with the gasoline loading rack provisions of 40 CFR 63, Subpart CC – National Emission Standards for Petroleum Refineries, by August 18, 1998. Cenex proposed to install a gasoline vapor collection system and enclosed flare for the reduction of Hazardous Air Pollutants (HAPs) resulting from the loading of gasoline. A vapor combustion unit (VCU) was added to the product loading rack. The gasoline vapors would be collected from the trucks during loading, then routed to an enclosed flare where combustion would occur. The result of this project would be an overall reduction in the amount of VOCs (503.7 TPY) and HAPs emitted, but CO and NO_x emissions would increase slightly (4.54 TPY and 1.82 TPY).

The product loading rack is used to transfer refinery products (gasoline, burner and/or diesel fuels) from tank storage to trucks, which transport gasoline and other products, to retail outlets. The loading rack consists of three arms, each with a capacity of 500 gpm. However, only two loading arms are presently used for loading gasoline at any one time. A maximum gasoline-loading rate of 2000 gpm, a maximum short-term rate, was modeled to account for future expansion.

Because Cenex's product loading rack VCU is defined as an incinerator under 75-2-215, Montana Code Annotated (MCA), 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. Cenex and the Department identified the following HAPs from the flare, which were used in the health risk assessment. These constituents are typical components of Cenex's gasoline:

1. Benzene
2. Toluene
3. Ethyl Benzene
4. Xylenes
5. Hexane
6. 2,2,4 Trimethylpentane
7. Cumene
8. Naphthalene
9. Biphenyl

The reference concentration for Benzene was obtained from Environmental Protection Agency's (EPA) IRIS database. The ISCT3 modeling performed by Cenex, for the HAPs identified above, demonstrated compliance with the negligible risk requirement.

MAQP #1821-05 was issued to Cenex on September 3, 2000, to revamp its No. 1 Crude Unit in order to increase crude capacity, improve product quality, and enhance energy recovery. The project involved the replacement and upgrade of various heat exchangers, pumps, valves, towers, and other equipment. Only VOC emissions were affected by the new equipment. The capacity of the No. 1 Crude Unit was expected to increase by 10,000 or more barrels per stream day.

No increase in allowable emissions was sought under this permit application. The project would actually decrease VOC emissions from the No. 1 Crude Unit. However, increasing the capacity of the No. 1 Crude Unit was expected to increase the current utilization of other units throughout the refinery and thus possibly increase actual site-wide emissions, as compared to previous historical levels. Therefore, the permit included enforceable limits, requested by Cenex, on future site-wide emissions. The limits allow emission increases to remain below the applicable significant modification thresholds that trigger the NSR program for PSD and Nonattainment Area (NAA) permitting.

The site-wide limits were calculated based on the addition of the PSD/NAA significance level for each particular pollutant to the actual refinery emissions from April 1998, through March 2000, for SO₂, NO_x, CO, PM₁₀, and particulate matter (PM) minus 0.1 TPY to remain below the significance level. A similar methodology was used for the VOC emissions cap, except that baseline data from the time period 1993 and 1999 were used to track creditable increases and decreases in emissions. The site-wide limits are listed in the following table.

Pollutant	Period Considered for Prior Actual Emissions	Average Emissions over 2-yr Period (TPY)	PSD/NAA Significance Level (TPY)	Proposed Emissions Cap (TPY)
SO ₂	April 1998-March 2000	2940.4	40	2980.3
NO _x	April 1998-March 2000	959.5	40	999.4
CO	April 1998-March 2000	430.8	100	530.7
VOC	1993-1999	1927.6	40	1967.5
PM ₁₀	April 1998-March 2000	137.3	15	152.2
PM	April 1998-March 2000	137.3	25	162.2

For example, the SO₂ annual emissions cap was calculated as follows:

Average refinery-wide SO₂ emissions in the period of April 1998 through 2000 added to the PSD/NAA significance level for SO₂ minus 0.1 TPY =
 $2940.4 \text{ TPY} + 40 \text{ TPY} - 0.1 \text{ TPY} = 2980.3 \text{ TPY} = \text{Annual emissions cap.}$
 MAQP#1821-05 replaced MAQP #1821-04.

MAQP #1821-06 was issued on April 26, 2001, for the installation and operation of eight temporary, portable Genertek reciprocating engine electricity generators and two accompanying distillate fuel storage tanks. Each generator is capable of generating approximately 2.5 megawatts of power. These generators are necessary because of the high cost of electricity. The operation of the generators will not occur beyond two years and is not expected to last for an extended period of time, but rather only for the length of time necessary for Cenex to acquire a more economical supply of power.

Because these generators would only be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of these generators is minor. In addition, the installation of these generators qualifies as a “temporary source” under the PSD permitting program because the permit will limit the operation of these generators to a time period of less than 2 years. Therefore, Cenex would not need to comply 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 required compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 would be ensured. In addition, Cenex would be responsible for complying with all applicable air quality standards. In order to keep this permitting action below the threshold of nonattainment area permitting requirements, Cenex requested a limitation to keep the project’s potential emissions of SO₂ below 40 tons. MAQP #1821-06 replaced MAQP #1821-05.

MAQP #1821-07 was issued on August 28, 2001, to change the wording regarding the stack height on the temporary generators, to allow for the installation of mufflers on those stacks, thus increasing the total stack height. In addition, the Department modified the permit to eliminate references to the repealed odor rule, to correct conditions improperly referencing the incinerator rule, and to update a testing frequency on the product loading rack VCU based on the Title V permit term. MAQP #1821-07 replaced MAQP #1821-06.

On June 3, 2002, the Department received a request from Cenex to modify MAQP #1821-07 to remove all references to 8 temporary, portable electricity generators. The generators were permitted under MAQP #1821-06, with further clarification added in MAQP #1821-07 regarding generator stack height. The generators have not been operated since August 10, 2001, and Cenex has no intention of operating them in the future. The references to the generators were removed, and the generators are no longer included in Cenex's permitted equipment. **MAQP #1821-08** replaced MAQP #1821-07.

On March 13, 2003, the Department received a complete permit application from Cenex to modify MAQP #1821-08 to add a new Ultra Low Sulfur Diesel (ULSD) Unit, Hydrogen Plant, and associated equipment to meet the EPA's 15 parts per million (ppm) sulfur standard for highway diesel fuel for 2006. The permit action removed the Middle Distillate Unifiner (MDU) charge heater, MDU stripper heater, MDU fugitives, and the #3 and #4 Unifier Compressors. The ULSD Unit included two heaters, four compressors, C-901 A/B and C-902 A/B, process drains, and fugitive piping components. The Hydrogen Plant included a single fired reformer heater, process drains, and fugitive piping components.

The treated stream from the ULSD Unit was separated into its constituent fuel blending products or into material needing further refining. The resulting stream was then stored in existing tanks and one new tank (128). Three existing tanks (73, 86, and 117) were converted to natural gas blanketed tanks to reduce emissions of VOCs from the ULSD Unit feed stock product streams. Cenex was to install a new TGTU for both the SRU #1 and #2 trains that will be operational prior to startup of the ULSD Unit but technically are not part of this permitting action. **MAQP #1821-09** replaced MAQP #1821-08.

On July 30, 2003, the Department received a complete application from CHS to modify MAQP #1821-09. The application was complete with the addition of modeling information provided to the Department on August 22, 2003. CHS requested to add a new TGTU and associated equipment for Zone A's SRU #1 and SRU #2 trains to control and reduce SO₂ emissions from this source. CHS submitted modeling to the Department for a determination of a minimum stack height for the existing SRU #1 and SRU #2 tail gas incinerator stack. CHS also submitted a letter to the Department to change the name on the permit from Cenex to CHS. The permit action added the new TGTU, set a minimum stack height for the tail gas incinerator stack, and changed the name on the permit from Cenex to CHS. **MAQP #1821-10** replaced MAQP #1821-09.

On June 1, 2004, the Department received two applications from CHS to modify MAQP #1821-10. The applications were complete with the addition of requested information provided to the Department on June 16, 2004. In one application CHS requested to change the nomenclature for Reformer Heater H-801 to Reformer Heater H-1001. H-801 was previously permitted during the ULSD project (MAQP #1821-09), at 150- MMBtu/hr. CHS requested to change the size of Reformer Heater H-801 (H-1001) from 150-MMBtu/hr to 161.56-MMBtu/hr. In the other application CHS requested to increase the PAL for CO from 530.7 tons per year to 678.2 tons per year based on new information obtained by CHS. The new information was obtained after the installation of a CO continuous emission monitor (CEMS) on the FCCU Stack. Emissions of CO from the FCCU Stack were assumed to be zero until the installation of the CEMS. CHS also requested that specific emission limits, standards, and schedules required by the CHS Consent Decree be incorporated into the permit. **MAQP #1821-11** replaced MAQP #1821-10.

On December 15, 2004, the Department received a letter from CHS to amend MAQP #1821-11. The changes were administrative, primarily related to changing routine reporting requirements from a monthly basis to quarterly. The changes to the permit were made under the provisions of ARM 17.8.764, Administrative Amendment to Permit. **MAQP #1821-12** replaced MAQP #1821-11.

On March 28, 2006, the Department issued **MAQP #1821-13** to CHS to build a new 15,000-barrel per day (BPD) delayed coker unit and associated equipment. The new delayed coker unit allows CHS to increase gasoline and diesel production by 10-15% by processing heavy streams that formerly resulted in asphalt (asphalt production is expected to decrease by approximately 75%, but the capability to produce asphalt at current levels was maintained and no emission credits were taken with respect to any possible reduction in asphalt production) without increasing overall crude capacity at the refinery. The delayed coker unit produces 800 short tons per day of a solid petroleum coke product. To accommodate the downstream changes created by the new delayed coker unit, several other units will be modified including the Zone D FCC Feed Hydrotreater, FCCU, ULSD Unit, and Hydrofluoric Acid (HF) Alky Unit. Other units will be added: Delayed Coker SRU/TGTU/TGI, NHT Unit, NHT Charge Heater, Boiler No. 11, Light Products Railcar Loading Facility, and two new tanks will be added to the Tank Farm. Other units will be shut down: the Propane Deasphalting Unit, Unifiner Compressors No. 1 and 2, No. 2 Naphtha Unifier Charge Heater and Reboiler, BP2 Pitch Heater, and Boilers No. 3 and 4. The VCU associated with the new Light Products Railcar Loading Facility and the Coker Unit TGI were subject to and the requirements of 75-2-215, MCA and ARM 17.8.770, Additional Requirements for Incinerators. The Delayed Coker project and associated equipment modifications did not cause a net emission increase greater than significant levels and, therefore, does not require a New Source Review (NSR) analysis.

The net emission changes were as follows:

Pollutant	Total Project PTE (TPY)	Contemporaneous Emission Changes (TPY)	Net Emissions Change (TPY)	PSD Significance Level (TPY)
NO _x	39.2	-7.5	31.8	40
VOC	-1.5	-53.3	-54.8	40
CO	106.7	-23.2	83.5	100
SO ₂	39.7	0.0	39.7	40
PM	7.6	6.6	14.2	25
PM ₁₀	6.7	6.6	13.3	15

The following is a summary of the CO emissions included in the CO netting analysis: Coker project (+106.7 TPY), emergency generator (+0.44 TPY, start-up in 2002), Zone A TGTU project (+8.3 TPY, initial startup at end of 2004), and Ultra Low Sulfur Diesel project (-31.9 TPY, started up in 2005). MAQP #1821-13 replaced MAQP #1821-12.

On May 4, 2006, the Department received a complete application from CHS to incorporate the final design of three emission sources associated with the new 15,000 BPD delayed coker unit project permitted under MAQP #1821-13. The final design capacities have increased for the new NHT Charge Heater, the new Coker Charge Heater and the new Boiler No. 11. The application also includes a request to reduce the refinery-wide fuel oil burning SO₂ emission limitation. This reduction allows CHS to stay below the significance threshold for the applicability of the New Source Review-PSD program. The maximum firing rates are proposed to increase with the current permitting action. The following summarizes the originally permitted firing rates (MAQP #1821-13) and the new proposed firing rates for the heaters and the boiler:

NHT Charge Heater: 13.2 to 20.1 million British thermal units – Lower Heating Value per hour (MMBtu-LHV/hr) (22.1 million British thermal units – Higher Heating Value per hour (MMBtu-HHV/hr))

Coker Charge Heater: 129.3 to 146.2 MMBtu-LHV/hr (160.9 MMBtu-HHV/hr)

Boiler #11: 175.9 to 190.1 MMBtu-LHV/hr (209.1 MMBtu-HHV/hr)

CHS also requested several clarifications to the permit. Under MAQP #1821-13 several 12-month rolling limits were established for modified older equipment and limits for new equipment. CHS requested clarifications be included to determine when compliance would need to be demonstrated for these new limits. MAQP #1821-13 went final on March 28, 2006, and CHS is required to demonstrate compliance with the new limitations from this date forward. For the 12-month rolling limits proposed under MAQP #1821-13 and any changes to limitations, CHS would be required to demonstrate compliance on a monthly rolling basis calculated from March 28, 2006. For modified units the limitations will have zero emissions until modifications are made. New units will have zero emissions until start-up of these units. Start-up is defined as the time that the unit is combusting fuel, not after the start-up demonstration period. Some units have clearly designated compliance timeframes based on the consent decree. These limitations and associated time periods are listed within the permit.

The Department agreed that the heading to Section X.A.3 can include the “*Naphtha Hydrotreating Unit*”; Section D.1.c is based on a 30-day rolling average; Section X.D.7.a.ii should state that the SO₂ limit is based on a 12-hour average; and that Section XI.E.3 should be revised to remove the requirement for a stack gas volumetric flow rate monitor. The Department made some clarifications to the language in Section X.D.6.b. The Department’s intent in permitting the coke pile with enclosures was to ensure that at no time would the coke pile be higher than the top of the enclosure walls at any point on the pile, not only the portion of the pile that is adjacent to the wall.

The Department did not believe it was necessary to designate the Sour Water Storage Tank as a 40 CFR 60, Subpart Kb applicable tank, when currently these regulations do not apply. If CHS makes changes in the future and 40 CFR 60, Subpart Kb becomes applicable to the tank, then CHS can notify the Department and the Department can include the change in the next permit action.

The Department received comments from CHS on the preliminary determination of MAQP #1821-14 on June 21, 2006. The comments were editorial in nature and the changes were made prior to issuance of the Department Determination on MAQP #1821-14. CHS requested corrections to the PM, PM₁₀, NO_x netting values in contained in the permit analysis, and the Department agreed that the edits were needed. CHS also requested further clarification to the requirements of Section X.D.6.b of the permit.

CHS stated that the coke pile will be dropped from two coke drums to a location directly adjacent to the highest walls of the enclosure area. The height of the dropped coke piles will not exceed the height of the wall. If CHS is required to relocate and temporarily store the coke at another location within the enclosure area, CHS will not pile the coke higher than the walls adjacent to the temporary storage location. **MAQP #1821-14** replaced MAQP #1821-13.

On September 11, 2006, the Department received an application from CHS to incorporate the final design of emission sources associated with the new 15,000-BPD delayed coker unit project permitted under MAQP #1821-13 and revised under MAQP #1821-14. The changes included:

- Retaining Boiler #4 operations and permanently shutting down the CO Boiler;
- Modifying the FCCU Regenerator CO limit due to the air grid replacement;
- Rescinding the permitted debottleneck project for Zone D SRU/TGTU/TGI and revising the long term SO₂ potential to emit;
- Modifying the Zone E (Delayed Coker) SRU/TGTU/TGI - Incinerator design and NO_x limits;
- Rescinding the firing rate restriction and associated long-term emission limits, and revising VOC emission calculations for H-201 and H-202; and
- Removing the 99.9 MMBtu/hr restriction and reclassifying Boiler #10 as subject to NSPS Subpart Db.

On October 11, 2006, the Department received a request to temporarily stop review of the permit application until several additional proposals were submitted, which included:

- On October 24, 2006, the Department received a de minimis notification for stack design changes for the Delayed Coker Unit (Zone E) SRU Incinerator.
- On October 31, 2006, the Department received clarification on the ULSD project.
- On November 1, 2006, the Department received a request to limit the maximum heat rate capacity of the #2 N.U. Heater to below 40 MMBTU/hour in conformance with the CHS Consent Decree. CHS also requested that the Department re-initiate review of MAQP #1821-15.

All of the above changes allowed CHS to stay below the significance thresholds for the applicability of the New Source Review-PSD program. CHS also requested several clarifications to be included in the permit, and the Department suggested streamlining the permit's organization. **MAQP #1821-15** replaced MAQP #1821-14.

On October 10, 2007, the Department received an application from CHS to modify MAQP #1821-15 to incorporate the final design of the NHT Charge Heater. This heater was permitted as part of the refinery's delayed coker project permitted under MAQP #1821-13 and revised under MAQP #1821-14 and MAQP #1821-15. The modification to MAQP #1821-15 was requested to address an operating scenario that was overlooked during the delayed coker unit design process. This operating scenario is for the case in which the NHT unit is in operation, but the delayed coker unit is not. In this operating scenario, the characteristics of the naphtha being processed in the unit are such that additional heat input to the heater is required to achieve the design NHT Unit throughput. For this reason, CHS requested approval for an increase in the design firing rate of the NHT Charge Heater (H-8301). The following summarizes the permitted firing rates under MAQP #1821-15 and the new proposed firing rates for the NHT Charge Heater:

Maximum Firing Rate (LHV): 20.1 MMBtu-LHV/hr to 34.0 MMBtu-LHV/hr
Maximum Firing Rate (HHV): 22.1 MMBtu-HHV/hr to 37.4 MMBtu-HHV/hr

This change does not impact any of the other design conditions in the original delayed coker permit, including unit throughputs and operating rates. The application also includes a request to reduce the refinery-wide fuel oil burning SO₂ emission limitation. This reduction allows CHS to stay below the significance thresholds for the applicability of the New Source Review-PSD program. CHS also requested some administrative changes to the permit. **MAQP #1821-16** replaced MAQP #1821-15.

On February 25, 2008, the Department received a complete application from CHS to modify MAQP #1821-16 for the completion of two separate projects. For the first project, CHS proposed to construct a new 209.1 MMBtu-HHV/hr steam generating boiler (Boiler #12). This project includes the permanent shutdown of two existing boilers, Boilers #4 and #5, which have a combined capacity of 190 MMBtu-

LHV/hr. The two existing boilers are being shut down in part to meet the consent decree NO_x reduction requirements, as well as to generate NO_x offsets for this permitting action.¹ Due to the operational complexity of replacing two existing boilers with one new boiler in the refinery steam system, CHS requested to maintain the ability to operate the #5 Boiler for 1 year after initial start-up of Boiler #12. Combustion of fuel oil in the refinery boilers would also be eliminated primarily to generate NO_x offsets for this permitting action.

For the second project, CHS proposed an expansion of its railcar light product loading facilities. Although there would be no increase in refinery production from this expansion, the project would increase flexibility in the transportation of refinery products. After project completion, there would be a total of nine spots available at this loading rack for product loading into railcars. The railcar light product loading facility was originally permitted as part of the delayed coker project permitted under MAQP #1821-13 and revised under MAQP #1821-14, #1821-15, and #1821-16. This change does not require a modification to the originally permitted VCU since the maximum loading rate of 2,000 gallons per minute (gpm) will remain unchanged.

The application also included a request to reduce the limitation for SO₂ emissions from the combustion of alkylation unit polymer and fuel oil in all combustion devices from 127.6 TPY to 50 TPY (for alkylation unit polymer only since fuel oil combustion in refinery boilers will be eliminated). Although the potential to emit for the combustion of alkylation unit polymer in the Alkylation Unit Hot Oil Heater is estimated to be around 8.3 TPY for SO₂ (based on a specific gravity of 0.7 and a sulfur content of 1 wt%; the exact potential to emit has not been determined due to the variability of specific gravity and sulfur content), the allowable emissions are set at 50 TPY in this permitting action. According to ARM 17.8.801(24)(f), the decrease in actual emissions from the elimination of fuel oil combustion in refinery boilers is creditable for PSD purposes provided the old level of actual emission or the old level of allowable emissions, *whichever is lower*, exceeds the new level of actual emissions and the decrease in emissions is federally enforceable at and after the time that actual construction begins. Since the old level of actual emissions is lower than the old level of allowable emissions for combustion of fuel oil in refinery boilers, CHS requested a creditable reduction based on actual emissions from the boilers. This reduction resulted in a total of 50 TPY SO₂ allowed for the combustion of alkylation unit polymer in the Alkylation Unit Hot Oil Heater, the only unit that is part of the original SO₂ limitation for fuel oil combustion devices that will continue to operate. While it appears that the emissions from the combustion of alkylation unit polymer would be allowed to increase through this permitting action, it is important to note that physical modifications and/or changes in the method of operation would first have to occur for the Alkylation Unit Hot Oil Heater to emit more than its estimated potential of 8.3 TPY (note: the exact potential to emit has not been determined at this time). As acknowledged by CHS, a modification and/or change in method of operation to this unit would require a permit modification.

¹. This is later clarified in the permit history for MAQP #1821-21. No creditable NO_x emissions reductions from the shutdown of Boiler #4 and #5 were used in the permit for construction of new Boiler #12 (MAQP #1821-17).

Therefore, the Department does not anticipate any increase in actual emissions from this unit, even though the allowable has been set at 50 TPY. In addition, should CHS eliminate or reduce the combustion of alkylation unit polymer in future permit actions in order to have a creditable decrease for PSD purposes, only the change in actual emissions would be available since the actual emissions will be lower than the allowable, unless a modification to the unit is made.

In addition, CHS requested that the permit CO emission limits for Boiler #11 be changed to 36.63 TPY and 15.26 lb/hr, based on a revised emission factor from performance test data completed in 2007 for Boiler #11 used to calculate the PTE. All of these changes allow CHS to stay below the significance thresholds for the applicability of the New Source Review-PSD program.

CHS also requested some additional administrative changes to the permit, including clarification of the applicability of 40 CFR 63, Subpart DDDDD: NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters to various sources given the fact that the federal rule was vacated on July 30, 2007. Although the federal rule has been vacated, the vacated federal rule remains incorporated by reference in ARM 17.8.103 and ARM 17.8.302 (with the applicable publication date specified in ARM 17.8.102) at the time of **MAQP #1821-17** issuance and as such, it remains an applicable requirement under state rules; each applicable permit condition has been marked 'State-Only Requirement'.

On April 1, 2008, CHS requested that the Department delay issuance of the preliminary determination for this permit application until additional information could be submitted regarding alternative coke handling practices. This additional information was submitted to the Department on April 3, 2008, with follow-up information received by the Department on April 14, 2008. CHS requested that an alternative coke handling process be included in MAQP #1821-17. The coke handling process, originally permitted as part of the delayed coker project, included the use of conveyors to transport coke to a crusher and to a railcar loading system. Because the system is enclosed, it is not possible to transport coke to the crusher and loading system without the use of the conveyors. CHS has since identified the need for an alternate coke handling method to be used when the conveyors are out of operation for either planned or unplanned maintenance. MAQP #1821-17 replaced MAQP #1821-16.

On November 7, 2008, the Department received a MAQP application from CHS for a benzene reduction project. In this application, CHS requested to modify MAQP #1821-17, to allow construction of a new Benzene Reduction Unit within the Laurel refinery to meet the requirements of the Mobile Source Air Toxics Rule (40 CFR 80, Subpart L). This rule requires that the refinery's average gasoline benzene concentration in any annual averaging period not exceed 0.62 volume percent, beginning January 1, 2011. This new unit will be inserted in the middle of the existing Platformer Unit. The new process will receive feed from the high pressure separator of the existing Platformer unit and produce a heavy platformate stream that will go directly to product storage and a light platformate stream that will be treated further. The light platformate stream, concentrated with benzene, will undergo a benzene hydrogenation reaction to convert the benzene to cyclohexane. This stream will then be fed to the existing Platformer Unit's debutanizer.

Because the Benzene Reduction Unit includes a hydrogenation reaction, hydrogen is required for the process. For this reason, modification to the existing 1,000 Unit Hydrogen Plant is planned. This modification will essentially increase hydrogen production in the amount needed in the new process and includes the addition of a steam superheater and an Enhanced Heat Transfer Reformer (EHTR). In the existing process, hydrogen is produced by mixing natural gas and the hydrogen-rich Platformer Unit off gas stream with saturated steam. However, in the modified process, only natural gas will be used. Additionally, the steam used will be superheated to supply additional heat to the primary reformer by means of a higher inlet process gas temperature. This modified process will allow for an increase in the process feed gas flow at the same reformer heat duty. As a result, more hydrogen will be produced in the reformer without increasing the firing rate, and thus, emission rate, of the H-1001 Reformer Heater. For this reason, the H-1001 Reformer Heater is not a project affected emission unit.

In this application, CHS also requested to make enforceable the retrofit of the Platformer Heater with low NO_x burners. This modification is being done to achieve Consent Decree required NO_x reductions. This modification is not required by the Benzene Reduction project; however, the retrofit of the Platformer Heater will occur during the construction phase of the Benzene Reduction project.²

The Department reviewed this application and deemed it incomplete on December 1, 2008. The Department requested additional information to support the BACT analysis for the Platformer Splitter Reboiler. The Department received the requested follow-up information from CHS on December 15, 2008; the application was deemed complete as of this date.

In addition to making the requested changes, 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. **MAQP #1821-18** replaced MAQP #1821-17.

On February 27, 2009, the Department received a complete MAQP application from CHS requesting clarification of an existing NO_x emissions limit for Boiler #12. In this application, CHS requested that the averaging period for the NO_x pound per million British thermal unit (lb/MMBtu) limit be specified as a 365-day rolling average. CHS submitted information to support this averaging period as the original basis for the BACT analysis conducted in MAQP #1821-17 for Boiler #12. **MAQP #1821-19** replaced MAQP #1821-18.

On August 13, 2009, the Department received a complete application from CHS requesting a modification to MAQP #1821-19. CHS proposed to retrofit the existing Boiler #10 with a lower NO_x control technology burner and to update the permit limits for this unit accordingly. This project was completed on a voluntary basis by CHS in order to improve environmental performance and boiler reliability. On September 17, 2009, the Department received a revision to this application addressing the SO₂ BACT analysis for both Boiler #10 and the recently permitted

² The requirement to retrofit the Platformer Heater with low NO_x burners was removed in MAQP #1821-21. CHS elected to achieve the Consent Decree required NO_x reductions by using projects other than the Platformer Heater retrofit.

Platformer Splitter Reboiler. This application revision was submitted in consultation with the Department and revised the SO₂ BACT analysis to reflect the recently finalized NSPS Subpart Ja requirements. **MAQP #1821-20** replaced MAQP #1821-19.

On March 31, 2010, the Department received an application from CHS requesting a modification to MAQP #1821-20. Additional information was received on April 22, 2010 resulting in a complete application. The application and additional information included requests for several modifications within the permit.

During the issuance of MAQP #1821-17, it became apparent that the Department and CHS had differing interpretations of paragraphs 177 and 180 of the CHS Consent Decree (CD) with EPA and the State of Montana (Consent Decree CV-03-153-BLG-RFC). Based on these differing interpretations, CHS deemed it necessary to retroactively analyze previous permit actions, particularly associated with the Delayed Coker Project, where changes may be necessary as a result of interpreting the CD in an alternative manner. On October 26, 2009, CHS provided an analysis concluding that the Delayed Coker Project was properly permitted as a non-major modification under New Source Review (including both PSD and Non-attainment Area New Source Review (NNSR)). For four pollutants (CO, VOC, TSP, and PM₁₀), project related emissions increases determined under Step 1 of the required applicability analysis were below the applicable significance thresholds. For two pollutants (NO_x and SO₂), the net emissions change, including project related emissions increases and contemporaneous emissions changes, were below the applicability significance thresholds. Following review, the Department concurred with CHS' analysis. However, as a result of this re-examination, including updates and changes to the original Delayed Coker Project emissions calculations, the following updates to MAQP #1821-20 were necessary to accurately reflect the refinery's overall process and individual emitting units.

1. Coke Drum Steam Vent

The original Delayed Coker Permit application did not include an estimate of the emissions associated with depressurizing the coke drum as part of the decoking operation. Based on emissions quantified at another facility, CHS was able to estimate emissions from their Coke Drum Steam Vent. MAQP #1821-21 has been updated to include this emitting unit in addition to the limitations and conditions assigned to it.

2. FCCU Regenerator

As part of the CD requirements, CHS completed catalyst additive trials at the FCCU in order to reduce NO_x emissions. Upon completion of the trials, CHS proposed short term (7-day rolling average) and long term (365-day rolling average) concentration-based NO_x limits to EPA. CHS proposed a long term concentration limit of 65.1 parts per million, volumetric dry (ppm_{vd}) on a 365-day rolling average basis and a short term concentration limit of 102 ppm_{vd} on a 7-day rolling average basis. EPA has agreed to these proposed limitations and these limits have been included within MAQP #1821-21.

3. Boiler 12 and Railcar Light Product Loading Projects

Originally permitted within MAQP #1821-17, the Boiler 12 and Railcar Light Product Loading Projects were included in the same permit application for administrative convenience only and should not be included as part of the Delayed Coker Project's emissions increase calculations. The Department agrees that the two projects were not substantially related and had no apparent interconnection to each other or to the Delayed Coker Project. The emissions calculations have been updated to reflect this conclusion.

4. Shutdown Timing for #4 and #5 Boilers

Included in the permitting action resulting in MAQP #1821-17 were shutdown dates for Boiler #4 and Boiler #5, which was tied to the initial startup of Boiler #12. Because emissions reductions from the boiler shutdowns were not required to avoid triggering the PSD requirements, the shutdown dates are no longer related to the startup of Boiler #12. The timing is driven by the CD, requiring all NO_x reduction projects (including shutdown of Boiler #4 and Boiler #5) to be completed by December 31, 2011. The shutdown timing has been updated.

5. Benzene Reduction Unit Project Updates

As a portion of the plan to achieve required NO_x emissions reductions as outlined in the CD, CHS had elected to retrofit the Platformer Heater (P-HTR-1) with low NO_x burners. The proposed retrofit was included in the application for the Benzene Reduction Project (MAQP #1821-18). CHS has determined that the retrofit will no longer be necessary to achieve the CD required NO_x reductions. All emission limitation and monitoring, reporting and notification requirements were removed.

6. Boiler #11 and Boiler #12 BACT Analysis Update

The original BACT analyses included in the permit applications associated with Boiler #11 and Boiler #12 did not specifically address CO emissions during startup and shutdown operations. During these operations, the boiler may experience an increase in CO emissions as a result of the ultra-low nitrogen oxide (NO_x) burner (ULNB) design. Based on an analysis of data collected during startup and shutdown operations for Boiler #11 and Boiler #12, a short term CO limit of 23 lb/hr on a 24-hour average basis, was included for periods of boiler startup and shutdown. Additionally, CHS proposed installation and operation of a volumetric stack flow rate monitor on Boiler #11 in order to be consistent with Boilers #10 and #12.

In addition to the aforementioned updates, CHS also requested a modification to the stack testing requirements to require stack testing every 2 years as opposed to annual stack testing for the following sources: Reactor Charge Heater (H-201), Fractionator Feed Heater (H-202), Reactor Charge Heater (H-901), Fractionator Reboiler (H-902), and NHT Charge Heater (H-8301). The Department approved this new testing schedule and MAQP #1821-21 has been updated accordingly. Additionally, various miscellaneous administrative changes were requested and included in this permitting action. **MAQP #1821-21** replaced MAQP #1821-20.

On July 27, 2010, the Department received a request to administratively amend MAQP #1821-21. The Department had inadvertently failed to modify all pertinent sections within MAQP #1821-20 to reflect the December 31, 2011 shutdown date for Boiler #4 and Boiler #5. CHS had requested the Department to administratively amend the permit to reflect this shutdown date in all applicable sections within the permit. CHS also requested the Department administratively amend the permit to include a reference to ppm_{vd} units where H₂S limits are expressed in grains per dry standard cubic feet (gr/dscf). The Department made the aforementioned administrative changes. **MAQP #1821-22** replaced MAQP #1821-21.

On November 1, 2010, the Department received an application from CHS requesting a modification to MAQP #1821-22.

“Mild Hydrocracker Project”

In this application, CHS proposed to convert the existing HDS Unit into a Mild Hydrocracker. Capacities of the existing 100 Unit Hydrogen Plant and the Zone D SRU/TGTU were proposed to be increased, the existing feed heater in the FCC Unit replaced and a rate-limiting pressure safety valve (PSV) in the NHT replaced. Collectively, these modifications are referred to as the “Mild Hydrocracker Project.” The primary purpose in converting the existing HDS Unit into a Mild Hydrocracker was to produce an increased volume of higher quality diesel fuel by utilizing more hydrogen to convert gasoil into diesel.

The Mild Hydrocracker Project consists of several components. Within the HDS, the following changes were slated:

- As a result of a significant increase in hydrogen consumption, modifications to the existing hydrogen supply and recycle system will be required. The existing C-201B gas-fired reciprocating engine and hydrogen recycle compressor will be replaced with an electric driven make-up hydrogen compressor. Additionally, a new electric-driven recycle compressor (C-203) will be added.
- The first two reactors will continue to contain a hydrotreating catalyst. The third reactor will be split from one bed of catalyst to two beds of catalyst, containing both hydrotreating and hydrocracking catalyst.
- Equipment to be added or modified as a result of volume or heat impacts include the following:
- A hydrogen bypass line will be added to allow for hydrogen addition both upstream and downstream of the H-201 Reactor Charge Heater.

- Changes in the separation process downstream of the reactors: Two new drums will be added, Hot and Cold Low Pressure Separators, along with additional heat exchange, including two sets of process heat exchangers, one cooling water heat exchanger and one fin-fan cooler.
- Trays within the H₂S Stripper will be replaced with higher capacity trays.
- The overhead condenser and pump associated with the H₂S Stripper Overhead Drum will be modified.
- A new “wild” naphtha product draw will be added to the H₂S Stripper Overhead Drum. This stream will be processed in the Crude Unit Naphtha Stabilizer and then routed to the NHT Unit.
- A bypass line for hydrocarbon feed to the Fractionator around the H-202 Fractionator Feed Heater may be added as a result of improved heat integration.
- The trays in the Fractionator will be replaced with higher capacity trays.
- A new flow loop on the Fractionator will be added returning a portion of the diesel draw to the Fractionator. The pump will also feed the Diesel Stripper. The loop will include a new pump, a fin-fan cooler and a steam generator.
- The trays in the existing Diesel Stripper will be replaced with higher capacity trays.
- New larger pump(s) will be added on the loop between the Diesel Stripper and the Diesel Reboiler. These pump(s) may also be used for diesel product.
- The Diesel Product Cooler (fin-fan) will be replaced with a higher capacity cooler.
- New higher capacity packing will be installed in the HP Absorber. Water circulation on the absorber will be eliminated.

Within the SRU, the following physical changes were proposed:

- Replace and upgrade the acid gas burner;
- Replace the reaction furnace and upgrade to higher pressure and temperature capability;
- Replace and upgrade the waste heat boiler for higher pressure steam generation;
- Replace and upgrade the three steam reheaters;
- Upgrade the #1 sulfur condenser; and

- Add new electric boiler feedwater pumps to accommodate the higher pressure steam generation.

Within the TGTU, the following physical changes were proposed:

- The trays in the quench tower and amine absorber will be replaced with higher vapor capacity trays;
- The cooling system will be improved through increased circulation and minor piping modifications to control the maximum temperature of the circulating amine; and
- The methyl diethanolamine amine (MDEA) used in the absorption section of the TGTU will be replaced with a proprietary high performance amine blend.

Within the 100 Unit Hydrogen Plant, the following changes were proposed:

- A new H-102 Reformer Heater will be added to operate in parallel with the existing H-101 Reformer Heater;
- Modification of existing BFW pumps for increased capacity and a new larger condensate cooler;
- Addition of new pumps to circulate water through the steam generation coil on the new reformer heater;
- Modification of the existing steam drum internals to handle higher steam loads;
- Replace end of life trays within the deaerator tower with higher capacity trays;
- Replace the hot and cold condensate drums with upgraded internals and more corrosion resistant metallurgy;
- Replace absorbent and valves on the PSA skid; and
- Remove equipment related to the use of propane as the feed stream to the 100 Unit Hydrogen Plant.

“FCCU Charge Heater-NEW”

CHS also proposed installation of a new FCCU Charge Heater (60 MMBtu-HHV/hr) to replace the existing FCC Charge Heater (FCC-Heater-1) that is near the end of its mechanical life. The new heater will be installed and started up on the same schedule as the conversion of the HDS Unit to a Mild Hydrocracker.

“ULSD Burner Fuel Project”

The application also included information related to an additional project that is proposed to be completed at the refinery concurrent with the project discussed above. The project involves adding the flexibility to recover additional Burner Fuel, rather than Diesel Fuel, within the existing ULSD unit. The feed rate to the ULSD Unit will not increase with this project. This project is referred to as the “ULSD Burner Fuel Project.”

In addition to the aforementioned projects, CHS requested the Department to incorporate several administrative changes. **MAQP #1821-23** replaced MAQP #1821-22.

On January 10, 2011, the Department received a request to administratively amend MAQP #1821-23. In review of the Department Decision for MAQP #1821-23 issued on December 30, 2010, CHS identified areas within the permit that required further clarification based on their comments submitted on the Preliminary Determination issued for MAQP #1821-23. **MAQP #1821-24** replaced MAQP #1821-23.

On April 12, 2011, the Department received an application from CHS for a modification to MAQP #1821-24. The modification request detailed proposed changes to a *de minimis* request approved by the Department on December 10, 2010 as well as proposed construction of two product storage tanks.

On December 6, 2010, the Department received a *de minimis* notification from CHS proposing construction of a new 100,000 barrel (bbl) storage tank (Tank 133) for the purpose of storing asphalt. Emissions increases as a result of the proposed project were calculated to be less than the *de minimis* threshold of 5 tpy, with no emissions from each of the regulated pollutants exceeding 1.44 tpy. Although CHS justified the project from an economics standpoint for asphalt service only, CHS determined that during the times of year that asphalt storage is not necessary, it would be advantageous to have the extra tank capacity available to store other materials, such as gas oil and diesel. These materials may accumulate in anticipation of or as a result of a unit shutdown. Within the April 12, 2011 application, CHS proposed installation of additional pumps and piping to allow for gas oil and diesel to be stored as well as asphalt as previously approved for Tank 133.

A separate project detailed within the April 12, 2011 application included construction of two new product storage tanks, collectively referred to as the Tanks 135 and 136 Project. The Tanks 135 and 136 Project included construction of two new 120,000 bbl external floating roof (EFR) product storage tanks and associated pumps and piping to allow more flexible storage of various gasoline and/or diesel components and finished products produced at the refinery. Tank 135 would be installed in the East Tank Farm located on the east side of Highway 212. With the current refinery piping configuration, this tank would store only finished gasoline and diesel products. Tank 136 would be installed in the South Tank Farm located on the west side of Highway 212. With the current refinery piping configuration, this tank would be available to store both component and finished gasoline and diesel products. To avoid restriction of service of the tanks, project emissions increase calculations were based conservatively on storage of gasoline year-round as well as current maximum refinery production capability.

Within the April 12, 2011 application, CHS also provided supplemental information to the BACT analysis included in the original permitting application for the Coker Charge Heater (H-7501) originally permitted as a part of the Delayed Coker project (1821-13 with revisions 1821-14 through 1821-16). This supplemental information was submitted with the purpose of laying the foundation for a proposed additional short-term CO emissions limit. **MAQP #1821-25** replaced MAQP #1821-24.

On November 8, 2011, the Department received an application from CHS for a modification to MAQP #1821-25. The application included three separate projects, grouped together into one action for administrative convenience. CHS proposed the following projects within this application:

1. #1 Crude Unit Revamp Project
2. Wastewater Facilities Project
3. Product Blending Project

The application also included the following:

1. Review of the regulatory applicability to existing Sour Water Storage Tanks 128 and 129.
2. Updates to the Mild Hydrocracker Project, which was permitted as part of MAQP #1821-23 and MAQP #1821-24.
3. Review of the regulatory applicability to the Product Storage Projects, which was permitted as part of MAQP #1821-25.

#1 Crude Unit Revamp Project

The #1 Crude Unit Revamp Project was proposed with the intention of improving the overall efficiency of the refinery by maximizing diesel and gas oil recovery in the atmospheric and vacuum processes at the #1 Crude Unit. The project would aid in accounting for changes in crude quality that have been evident historically and are expected in the future. Modifications in the vacuum process are expected to result in an improved separation of the diesel and gas oil components such that diesel will not be carried with the gasoil to units downstream of the Crude Unit. Modifications in the vacuum process will result in the recovery of additional gas oil from the asphalt and improved quality of feed to the downstream Delayed Coker Unit.

The #1 Crude Unit Revamp Project included the following key components:

- Improvements to the preheat exchanger trains to ensure additional heat can be added to the crude oil upstream of the atmospheric column.
- Modifications to the atmospheric column from the diesel draw downward and to the associated condensing systems.
- Existing dry vacuum process will be changed to a wet vacuum system through the addition of steam.

- Redesign and replacement of the existing vacuum column.
- Installation of new equipment to recover a diesel stream from the new vacuum column.
- Addition, replacement and/or redesign of overhead and product cooling systems.

Wastewater Facilities Project

The proposed Wastewater Facilities Project is slated to improve the overall performance of the refinery wastewater handling and treatment facilities and to address anticipated future wastewater discharge quality requirements. The project is comprised of the following components:

- Installation of new Three Phase Separator(s) to remove solids and free oil from wastewater generated at the crude unit desalters.
- Installation of new American Petroleum Institute (API) Separator(s) and Corrugated Plate Interceptor (CPI) Separator(s) to treat process wastewater generated at the older process units. The existing API Separator will be removed from service. As a note, emissions from the separators will be controlled with carbon canisters.
- Replacement of the existing activated sludge unit (ASU) (T-30). Replacement will be of the same size and will incorporate several design changes to improve the biological treatment efficiency.
- Installation of a second ASU and clarifier to be operated in parallel with the existing ASU and clarifier and will provide maintenance backup to the system.
- Installation of two new Sludge Handling Tanks to receive waste activated sludge from the clarifiers. The removed sludge will be dewatered and dried for offsite disposal.
- Installation of two new DAF Units to treat process wastewater from all of the process units. Emissions from the DAF Units will be controlled with carbon canisters. The existing DAF will be removed from service.

Product Blending Project

The objective of the Product Blending Project is to increase the volume of finished diesel and burner fuel available for sale. The project is comprised of the addition of new piping components; however, the changes will not result in a change to the operation of any process units at the refinery.

Additional Permit Changes

CHS conducted a review of regulatory applicability pertaining to sour water storage tanks 128 and 129, which were permitted as a result of CHS's permit application submitted on October 18, 2005, for the delayed coker project. Based on the review, CHS determined Tanks 128 and 129 to not be subject to 40 CFR 60 (NSPS) and also determined Tanks 128 and 129 to be labeled as Group 2 storage vessels as described within 40 CFR 63, Subpart CC. Therefore, CHS requested the permit, specifically the Title V Operating Permit, be updated to reflect these new determinations of regulatory applicability.

As part of MAQP #1821-23, CHS proposed to convert the existing Hydrodesulfurization (HDS) Unit into a Mild Hydrocracker. Since issuance of this permit, various portions of this project scope were modified, with only one change resulting in a change in the original project emissions calculations. Potential emissions increased slightly; however, continued to remain below significance levels with respect to Prevention of Significant Deterioration (PSD) review. A summary of the updated emissions inventory has been included in the permit analysis for this permit action.

CHS additionally conducted a review of regulatory applicability pertaining to Tanks 133, 135, and 136. As part of the original permitting action (MAQP #1821-25) associated with these product storage tanks, CHS identified the applicability of NSPS Subpart GGGa to the piping components associated with the three new storage tanks. This applicability has been reevaluated. NSPS Subpart GGGa applies to affected facilities at petroleum refineries that are constructed, reconstructed or modified after November 7, 2006. Specifically, as stated within NSPS Subpart GGGa, the group of all the equipment (defined in §60.591a) within a process unit is an affected facility. The definition of "process unit," as defined in 60.590a(e) is as follows:

"Process unit means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product."

The applicability of NSPS Subpart GGGa has been determined to stop at the boundary of a process area and does not include piping components between the process area and storage tanks, therefore, eliminating the components associated with Tanks 133, 135, and 136 from being applicable to NSPS Subpart GGGa. Although this equipment is not specifically applicable under NSPS Subpart GGGa, the VOC BACT (Refinery Equipment) determination from MAQP #1821-25 stated that "an effective monitoring and maintenance program or Leak Detection and Repair (LDAR) program (as described under NSPS Subpart VVa) meeting the requirements of NSPS Subpart GGGa constitutes VOC BACT for equipment leaks from new components." The Department has modified the requirements for institution of a monitoring and maintenance program to more accurately reflect the VOC BACT (Refinery Equipment) determination; thus removing the NSPS Subpart GGGa reference and including the pertinent language within the condition itself. The conditions are now reflective of only the BACT determination.

CHS also requested several various administrative changes and clarification additions.

MAQP #1821-26 replaced MAQP #1821-25.

On June 4, 2012, CHS Inc. submitted a permit application to the Department to modify MAQP # 1821-26 and Title V Operating Permit (OP) #OP1821-10. The application was submitted to modify two previously permitted refinery projects, and to construct a new gasoline and diesel truck loading facility as summarized below:

Mild Hydrocracker (MHC) Project Update. This application incorporated the final design and location of the Fluid Catalytic Cracking (FCC) Charge Heater being replaced as part of the MHC Project. The FCC Charge Heater was originally approved at 60 million british thermal units per hour (MMBtu/hr) as part of the MHC project (MAQP #1821-23). This permit application modified the size of the heater from 60 to 66 MMBtu/hr. In addition, the permit application reclassified the FCCU Reactor/Regenerator as a “modified” emitting unit rather than an “affected unit,” and CHS requested to replace the existing Riser with a new Riser (and Riser design) as the current Riser was nearing the end of its mechanical life.

Benzene Reduction Unit (BRU) Project Update. This project involved a modification of the H-1001 Reformer Heater to achieve the design hydrogen production rate within the 1000 Unit Hydrogen Plant. Expansion of the 1000 Unit Hydrogen Plant was included in the MAQP #1821-18. However, the 1000 Unit Hydrogen Plant expansion changed the characteristics of the PSA tailgas (e.g. the heat content (British thermal units per standard cubic feet (Btu/scf) declined and the volume produced increased (standard cubic feet per minute (scfm)). According to CHS, the total heat input associated with the PSA tailgas remained nearly the same. As a result, the existing PSA tailgas burners on the H-1001 Reformer Heater could not handle the increased volume of PSA tailgas without excessive pressure drop and the 1000 Unit Hydrogen Plant production rate became limited by the volume of PSA tailgas that could be combusted. The permit modification replaced the PSA tailgas burner tips with tips that have larger ports such that all of the PSA tailgas generated could be combusted in H-1001. CHS proposed replacement of the supplemental fuel (e.g. natural gas, refinery fuel gas) burners in H-1001 to achieve improved NOx emission performance. The previous heater was physically capable of combusting refinery fuel gas but could not meet the existing oxides of nitrogen (NOx) permit limits while doing so. Additionally, the modified heater will have a higher maximum design firing rate (191.8 MMBtu-HHV/hr post project versus 177.7 MMBtu-HHV/hr) and a slight increase in the actual firing rate.

Gasoline and Distillate Truck Loading Facilities Project. This permit application also proposed the construction of new gasoline and distillate truck loading facilities, including new storage tanks, loading rack and VCU. The goal of the project was to improve safety and reduce truck congestion by relocating the gasoline and distillate truck loading operation to the east side of Highway 212. As proposed by CHS, the existing truck loading rack and associated equipment will be permanently removed from service within 180 days of startup of the new loading facility. The permit modification also added a new propane storage and loading facility.

In addition to those items mentioned above, this permit action included miscellaneous updates and amendments. CHS requested to discontinue use of the sulfur dioxide (SO₂) Continuous Emissions Monitoring System (CEMs) on the H-1001 stack because H-1001 was subject to 40 Code of Federal Regulations (CFR) 60, Subpart Ja which included exemptions from hydrogen sulfide/sulfur dioxide (H₂S/SO₂) monitoring requirements for fuel gas streams that are inherently low in sulfur content. The primary fuel to H-1001, PSA tailgas is inherently low in sulfur content. CHS already monitors the H₂S content of the refinery fuel gas (RFG) to be combusted in H-1001 as supplemental fuel, which would meet the monitoring requirements of Subpart Ja.

CHS requested that the Department remove condition IV.E.4 which requires the use of statistically significant F-factor values in determining compliance with NO_x and carbon monoxide (CO) limits for the H-102 Reformer Heater. Rather, CHS proposed that results of the required performance testing be used to calculate an appropriate emission factor to demonstrate ongoing compliance with NO_x and CO limits.

MAQP #1821-27 replaced MAQP #1821-28.

On November 14, 2012, CHS Inc. submitted a request to the Department to amend several items in their permit. The following provides a summary of the items that changed in MAQP #1821-27 as a result of this action:

- In Section IV.A.3, CHS requested to remove 40 CFR 60, Subpart Ja from this section of the permit as the units subject to this New Source Performance Standard (NSPS) are already identified in Section X.
- In Section VI.C.1 and XVI.C.6, CHS requested that the Department remove existing gasoline and distillate loading rack and associated VCU from the VOC limit in these sections. In addition, the Department removed the notification requirement on the existing truck loading rack and associated VCU.
- Section VI.G.1.d, required notification once the existing propane loading rack has been rendered inoperable. As clarification, CHS does intend to permanently shut down the existing propane loading rack but not the existing propane storage facilities as was previously stated in error in the CHS permit application. The Department removed the notification requirement on the existing propane loading rack. The Department understands that the propane storage facilities were not included in this action. Because the propane storage is not listed in the permit, this will not require an administrative change other than to note the clarification.
- In MAQP #1821-27, CHS proposed replacement of the burners in the H-1001 Reformer Heater. The firing rate and associated limits only apply once the heater has restarted after the retrofit. CHS requested that the Department clarify that the limits included in MAQP #1821-26 would apply until such time that the H-1001 Reformer Heater has gone through its shakedown period (CHS requested 180 days after initial startup). The Department clarified this by adding the limitations previously listed in MAQP #1821-26 back into the permit.

- The Department previously noted that there was an error in the CO limit for the H-1001 Reformer heater. As such, CHS requested that the limit in VIII.D.3.e be corrected as follows: 0.02 lb/MMBtu-HHV, or 16.8 tons per rolling 12-calendar month total.
- In Section X.D.2, CHS requested that the last sentence of the introductory paragraph be deleted as it incorrectly indicates that the conditions apply once the new FCC-Charge-Heater begins operation.
- CHS requested that Section X.D.2.a.a. be changed for consistency with the other emission limits in that that section as follows: The FCC-Heater-NEW shall be equipped with ULNB and the firing rate of the heater shall not exceed 66 MMBtu/hr-HHV based on a rolling 30-day average.
- CHS requested that Section X.G.2 and Section X.H be modified to reflect the fact that there isn't a CO CEMs on the new FCC-Heater-NEW.

MAQP #1821-28 replaced MAQP #1821-27.

On January 22, 2013, CHS Inc. submitted an application for a modification to MAQP #1821-28. As a result of the Mild Hydrocracker Project, the quantity of gasoil converted to diesel will generally increase and the quantity converted to gasoline will generally decrease. This will result in a lower rate of gasoline production at the FCCU and the downstream Alkylation Unit. According to CHS, these refinery gasoline component streams have relatively high octane ratings and are typically blended with gasoline component streams that have lower octane ratings to meet product octane specifications. CHS has determined that there may be times following the Mild Hydrocracker Project's startup that the refinery will not be able to produce enough of the higher octane gasoline components necessary to meet the minimum octane product specifications. As a result, CHS proposed to complete the Gasoline Component Unloading Project as included within the January 22, 2013 application. CHS also indicated that the impact from the MHC Project is not the only justification for completing the Gasoline Component Unloading Project. CHS anticipates that there may be other market-driven factors that will require CHS to increase or decrease the octane rating of its gasoline product in the future.

The January 22, 2013 application contained information necessary to incorporate permit changes associated with CHS's proposal to install the facilities necessary to unload various gasoline components from railcars to existing storage tanks such that these components can be blended into refinery products. The Gasoline Component Unloading project is considered an aggregate part of the previously approved Mild Hydrocracker Project and therefore, was evaluated as such for purposes of determining its regulatory applicability with respect to PSD applicability.

In addition to the proposed Gasoline Component Unloading project, CHS also requested the following changes to BACT permit conditions and monitoring requirements associated with the H-1001 Reformer Heater, FCC Charge Heater, and Gasoline and Distillate Truck Loading Rack VCU.

- For H-1001 and the FCC Charge Heater, CHS requested that permit conditions expressed in terms of MMBtu be removed from the permit and that permit limits in terms of mass (i.e. lb/hr and tons per rolling 12-calendar month total) be maintained.

CHS offered the following explanation for removal of these permit conditions:

The H-1001 Reformer Heater utilizes two fuel sources. The PSA tailgas fuel stream is generated within the 1000 Unit Hydrogen Plant and supplies the majority of the fuel required by the heater during normal operation. The supplemental fuel source is either refinery fuel gas (RFG) or natural gas. The RFG has a relatively consistent BTU content and is monitored through existing systems including an online process GC (i.e. not a CEM) and lab analysis of grab samples such that the composition and subsequently the BTU content of the RFG is characterized on a regular basis. In contrast, the PSA tailgas fuel stream has a BTU content that can vary significantly over the course of a day or week. Additionally, it does not have an online GC or a reliable grab sampling system such that its BTU content can be characterized in a frequent or accurate enough manner to be useful in assuring compliance with limits based on short term measurements of the fuel BTU content. CHS estimates that due to the sampling issues only 20% of the samples collected of the 1000 Unit PSA tailgas are valid samples. In consideration of this issue, CHS proposed in the comments to the Preliminary Determination for MAQP #1821-27 that a stack flue gas flow rate monitor be installed for use along with the existing NO_x and CO CEM to demonstrate compliance with mass emission limits in place of the proposed limits expressed in terms of MMBtu. CHS believes this approach is appropriate for the following reasons:

- *The proposed mass emission limits were derived by simply multiplying the MMBtu-based limits together;*
- *The mass limits better accomplish the goal of restricting the short and long term emissions from the H-1001 Reformer Heater through the use of continuous concentration and flow monitors rather than determining an average of a number of grab samples; and*
- *The mass limits are expressed in terms the CHS Operations staff has the ability to monitor in order to ensure continuous and ongoing compliance.*

As requested, the Department removed the permit conditions expressed in terms of MMBtu for the H-1001 Reformer Heater and the FCC Charge Heater.

- As included within the application for MAQP #1821-27, CHS proposed to install a new gasoline and distillate truck loading facility, which included an associated VCU as the control device for vapors displaced from the truck during the loading process. CHS identified BACT for the loading rack as a VCU that controls VOC emissions to a maximum of 10 mg/l of gasoline product loaded. The new loading rack is subject to 40 CFR 63 Subpart CC (NESHAP for Petroleum Refineries) requirements, which requires the loading rack to meet the requirements of 40 CFR 63 Subpart R. CHS requested that the BACT permit monitoring requirement be updated to more closely reflect the Subpart R requirement. The Department modified the condition as requested.

MAQP #1821-29 replaced MAQP #1821-28.

On April 15, 2013, CHS Inc. submitted an application for a modification to MAQP #1821-29. The application was submitted concurrently with CHS's request for renewal of Operating Permit OP1821-10 and included the following:

- 40 CFR 60, Subpart J applicability updates: Conditions indicating NSPS Subpart J applicability to all CHS Refinery's fuel gas combustion devices were updated to reflect NSPS Subpart Ja requirements, where necessary.
- Clarification of 40 CFR 60, Subpart Ja applicability: Specific to Boiler #12, CHS requested that the MAQP be clarified to reflect that Boiler #12 meets the NSPS Subpart Ja definition of a "fuel gas combustion device" requiring compliance with the SO₂ emission limit or the H₂S in fuel gas limit.
- Railcar Light Product Loading Rack NESHAP applicability: Based on the facility's SIC code, 40 CFR 63, Subpart CC applies to the light product loading racks and 40 CFR 63, Subpart R does not apply. CHS requested clarification of this applicability within the MAQP.
- 40 CFR 60, Subpart GGGa applicability updates: The MAQP identified applicability of NSPS Subpart GGGa to refinery fuel gas supply lines to Boiler #12. However, because Boiler #12 commenced construction after November 7, 2006, it is subject to NSPS Subpart GGGa.
- 40 CFR 60, Subpart VV/VVa applicability updates: NSPS Subpart VV or VVa apply to affected facilities in the Synthetic Organic Chemical Manufacturing Industry (SOCMI). The CHS refinery is not classified as a SOCMI industry. The LDAR rules that apply to the CHS refinery include NSPS Subparts GGG and GGGa and MACT Subpart CC. Each of these rules reference specific conditions in NSPS Subpart VV and VVa, CHS proposed reference only GGG or GGGa.
- Consent Decree reference updates: Several conditions in the MAQP still contained references to the consent decree where obligations have been met. CHS requested to have these references removed.
- References to Billings/Laurel SO₂ Emissions Control Plan, as approved into the SIP: CHS requested corrections be made to the MAQP where the SO₂ SIP was referenced incorrectly.
- "Plant-wide" emissions limits: Since issuance of MAQP #1821-05, inadvertently, changes have been made to the original list of emitting units to be included in these emission caps for each pollutant. Additionally, as a result of the addition and removal of various emitting units since the creation of these emission caps, the term "plant-wide" is no longer appropriate. CHS requested the list be corrected and the term "plant-wide" removed from the permit.

- Administrative Amendments: CHS requested various administrative changes be incorporated into the MAQP.

MAQP #1821-30 replaced #MAQP 1821-29.

On August 13, 2013, the Department received from CHS an application for modification of the MAQP and the associated Title V permit to modify limits for the H-901 and H-902 process heaters.

The H-901 heater is fired on refinery fuel gas, and its function is to heat the feed into the hydrogenation reactor, which serves to remove sulfur from the process stream. The sulfur reducing process occurs through what is called the Ultra Low Sulfur Diesel (ULSD) reactors. Heat is required by the H-901 process heater to assure the Ultra Low Sulfur Diesel reaction occurs with the appropriate sulfur removal efficiency required to make low sulfur fuels specifications.

The H-902 heater is also fired on refinery fuel gas, and this heater heats the sulfur-reduced process stream for fractionation and stripping back into naphtha, #1, and #2 diesel. An increased amount of heat from the H-902 heater provides for increased recovery of #1 diesel by allowing for increased stripping rates.

Due to changes in the quality of crude oil and the ULSD feed, which affects the sulfur removal process, increased market demand for #1 diesel, proposed to increase emissions limits on the H-901 and H-902 heaters. The H-901 and H-902 mass rate-based emission limits were originally determined in MAQP #1821-09. These limits were based on the heat input rate of the heaters, and the emissions rate guarantee of the ultra low oxides of nitrogen (NO_x) burner design selected as BACT. The design of the burners was based on a NO_x pound per million British Thermal Units (lb/MMBtu) guarantee. In the MAQP #1821-09 application, the maximum rated heat input capacity of the heaters were presented based on the maximum expected process heat input requirements of the heaters at that time. Limitations in the form of tons per rolling twelve (12) month period and pound per hour were accepted by CHS based on the expected needs of the burners.

CHS proposed to increase the heat input component of the emission limit calculation, maintaining the Ultra-Low NO_x Burner performance on a lb/MMBtu basis, and allowing for a higher firing rate in each heater. The proposed increased NO_x, carbon monoxide (CO), and volatile organic compounds (VOC) emission limits are based on an increase in maximum heat rate input from 27.46 million British thermal units per hour (MMBtu/hr) to 32.60 MMBtu/hr on the H-901 heater, and from 55.26 to 65.10 MMBtu/hr on the H-902 heater, on a higher heating value basis. CHS has not requested to increase allowable oxides of sulfur limits.

CHS also proposed to monitor emissions rates from the H-901 and H-902 heaters through use of Continuous Emissions Monitoring Systems (CEMS). This method supports increased compliance monitoring abilities for CHS, allowing for quicker compliance status determinations. At the request of CHS, the Department has incorporated this compliance demonstration method.

Because this action relaxes previously assigned permit limits at a major source, CHS presented a Prevention of Significant Deterioration (PSD) look-back to fulfill the requirements of ARM 17.8.827. This rule requires that if a permit limit is relaxed, it must be demonstrated that PSD was not circumvented during previous permit actions that relied on the more stringent permit limit. Because the heaters' capacities are larger than originally presented in 2003, CHS provided demonstration that if the associated increased capacity had been recognized in the 2003 application, and also in association with other associated projects applied for after 2003, it would not have made the ULSD project or the other associated projects subject to PSD. This analysis is included within the application on file with the Department.

MAQP #1821-31 replaced MAQP# 1821-30

On October 21, 2013, CHS Inc. submitted concurrent applications for a modification to MAQP #1821-30 and OP1821-12. At the time of receipt, permit actions were also under way for updates under OP1821-13, OP1821-14 and for MAQP#1821-31.

Under the proposed action, CHS added a new 100,000 barrel (approximately 4,040,000 gallon) intermediate storage tank. The tank was identified as Tank 146 and was a vertical fixed roof tank capable of storing sour gas oil, sweet gas oil, light coker gas oil, or raw diesel. Due to the physical properties of sweet and sour gas oil, a steam coil was also installed in Tank 146 to reduce the viscosity to a point low enough for pumping purposes. Additionally, when in sour gas oil service, raw diesel service or light coker gas oil service the tank would be blanketed with natural gas to prevent oxygen from entering the tank. The tank is for storage of the four identified intermediate products only and not allowed as a "final product" storage tank or for storage of other products not consistent with the four intermediate products identified in the application.

Additional Permit Actions. A De minimis request was also received by the Department on July 29, 2013, for piping modifications at the Railcar Light Product Loading Rack. Under the request, piping modifications were approved to allow converting loading spots that currently only allow gasoline loading to also allow diesel loading and for spots that currently only allow diesel loading to also allow gasoline loading. The MAQP did not have any language describing the piping detail of the loading spots. Since physical piping modifications were allowed under this de minimis request, this reference has been added for completeness. A De minimis request was also received by the Department on December 5, 2013, and approved on December 9, 2013. Since the de minimis request was issued prior to the end of the public comment period, this de minimis reference has been added for completeness. Under the de minimis request, the potential input of the #2 Crude Unit Vacuum Heater was lowered from 86 MMBtu-HHV/hr down to 62 MMBtu-HHV/hr.

MAQP #1821-32 replaced MAQP #1821-31.

On July 31, 2014, the Department received from CHS an application for replacement of the main refinery flare. The flare was reaching the end of its mechanical life, and was in need of replacement. The replacement flare is subject to New Source Performance Standards (NSPS) Subpart Ja (40 CFR 60 Subpart Ja), as well as 40 CFR 60.18 (Control Device and Work Practice Standards) and 40 CFR

63.11 (Control Device and Work Practice Requirements). Proposed as part of the main flare replacement project, was installation of a flare gas treatment and recovery system. Vent gases captured in the recovery system will be directed to amine treatment for removal of reduced sulfur compounds and returned to the refinery fuel gas system to be burned in fuel gas combustion units (displacing natural gas usage). During times when the amount of captured vent gases exceeds the flare gas recovery system capacity, the gases would pass through the liquid seal of the flare for destruction of the gas by combustion in the flare. Combustion of these gases is necessary to destroy the various components which would otherwise have potential to be emitted in amounts which would pose serious threat to human health and the environment.

CHS submitted as part of the flare replacement application a proposal to replace the current Zone D Sour Water Stripper with a new Two Stage Sour Water Stripper. The Zone D Sour Water Stripper was undersized for the amount of nitrogen content being seen in some crude oil supplies to CHS. Because flare gas recovery will result in additional sour water which must be treated, the needed upsizing of the Zone D Sour Water Stripper could also be determined related to the current flare project from a New Source Review (NSR) perspective, as sizing of the Sour Water Stripper would need to include the additional needs created by the flare gas recovery system. The new Sour Water Stripper allows the refinery to increase wash rates. The process generates two vent streams; one rich in reduced sulfur compounds that will be processed at the Sulfur Recovery Units, and one rich in ammonia, which will have some reduced sulfur and hydrocarbon as well. The ammonia stream will be sent to a caustic-based scrubber and ammonia combustor. The combustor is subject to Montana Code Annotated 75-2-215 incinerator review, as well as Best Achievable Control Technology review. Selective Catalytic Reduction control technology was required to control Oxides of Nitrogen from the combustion process, and waste heat in the ammonia combustor exhaust used to generate steam.

On August 27, 2014, the Department received supplemental information from CHS regarding additional scope of the flare gas recovery project. CHS proposed that the Zone E Flare (known as the Coker Flare), be equipped with a seal and necessary piping to provide for recovery of the Zone E flare gases. Zone E flare gas could go to the same refinery fuel gas treatment and recovery system, or through the Zone E Amine unit and to Zone E refinery fuel gas consumers.

In addition, administrative updates were made to remove language pertaining to timing of applicability of certain conditions or initial testing and notification requirements which are no longer applicable. Changes recognized in these updates include completion of conversion of the hydrosulfurization unit to the mild hydrocracker, replacement of the C-201B compressor with an electrically driven compressor, update of the #1 Crude Unit's NSPS applicability, completion of the H-1001 burner retrofit, and installation of the new FCC charge heater. **MAQP #1821-33** replaced MAQP #1821-32.

On November 7, 2014, the Montana Department of Environmental Quality (Department) received from CHS an application for three separate projects, as discussed below:

Crude Blending Project:

Over time, the quality of the crude oil supply to CHS has declined and become more variable. CHS proposed to install two new crude oil storage tanks each with a capacity of approximately 200,000 barrels. The tanks, used in conjunction with existing crude oil storage tanks, would provide improved segregation of crude oils with different characteristics such that an optimum crude oil blend can be supplied to the #1 and #2 Crude Units. As a result of optimizing the crude feed quality, the feed rate to each of the Crude Units may be able to increase by as much as 3,000 barrels per day, therefore, the increased utilization of the crude units, as well as the Ultra-Low Sulfur Diesel, Naphtha Hydrotreater, and Platformer Units, are accounted for in the project review. With exception of the new tanks and related piping, no physical modifications to existing equipment were proposed.

Tank 147 Project:

CHS installed a new 100,000 barrel capacity fixed roof tank (Tank 147) to be used for the storage of intermediate products. Installation of this tank allows CHS to better manage inventories during maintenance outages and to reduce the frequency of service changes for tanks that have multiple service capabilities.

This tank is insulated and heated to keep the intermediate at a workable viscosity, and designed with a natural gas blanketing system to avoid oxygen from contacting the stored intermediate products, to avoid downstream fouling. This project resulted in more tanks in dedicated service, but not in the ability to process additional crude oil or produce additional product on an annual basis.

Coke Trucking Project:

CHS added truck shipping of Petroleum Coke to the refinery. At times, due to railcar availability issues, the refinery must reduce production rates due to the limited petroleum coke storage. This project utilized the existing railcar loading system to load trucks when needed. This project did not require modification of any existing emission unit; however, the addition of fugitive road dust emissions is expected.

Administrative Changes:

CHS submitted to the Department the specification sheets for the flare gas recovery system compressors. The specification sheets demonstrate to the Department's satisfaction the size requirements identified in MAQP #1821-33. CHS suggested, and the Department agrees, that demonstration of compliance with the design of the flare gas recovery system compressors is most straightforward by requiring the make and model noted on the specification sheets to be installed. The condition regarding size of the compressors was replaced with language requiring that the specific make and model compressors be installed.

CHS also requested that the 'new' flare be referred to utilizing different terminology, for clarification purposes from an NSPS perspective. The Department updated the permit language as requested.

CHS requested that the requirement to monitor O₂ on the H-901 and H-902 heaters be removed. NO_x CEMS is required, including a flowrate monitor; however, the need for O₂ monitoring is not necessary because the relevant emissions limit for this condition is on a lb/hr basis. The Department removed the requirement for the NO_x CEMS as required by this condition to include an O₂ monitor.

MAQP #1821-34 replaced MAQP #1821-33

On September 16, 2015, the Department received an application from CHS for a large expansion to the existing refinery. Throughout the permit, the project is referred to as the Grassroots Hydrocracker Project (GRHC). The permit action included information submitted to process the MAQP application for both New Source Review and Prevention of Significant Deterioration (PSD) requirements. The primary objective of the GRHC project was to increase the diesel production capacity at the refinery.

The GRHC expanded diesel production with the addition of a new Hydrocracker (HC) Unit and supporting Hydrogen Plant (HRU). To accommodate the new HC, modifications were made within the existing #1 Crude Unit (#1 CRU), Mild Hydrocracker (MHC) and Fluidized Catalytic Cracking Unit (FCCU). To allow for increased product shipment by rail, the capability of the existing light product railcar loading rack was expanded. The GRHC also includes the installation of two new tanks and an increase in the amine treatment capacity at the refinery.

The new HC was designed to process approximately 25,000 barrels per day of feed. The unit includes three fired heaters including two identical Reactor Feed Heaters each with a design heat input capacity of 75 MMBtu/hr (HHV) and a Fractionator Feed Heater with a design heat input of 126.3 MMBtu/hr (HHV).

The new HRU includes a fired heater with a design heat input capacity of 562 MMBtu/hr (HHV). The reformer type hydrogen unit is designed to provide up to 40 MMSCFD of hydrogen. In addition to supporting the increased hydrogen demand associated with the project, the new HRU also increases the reliability of the hydrogen supply at the refinery.

Although not related to the GRHC project, the application also included a request to modify the short-term NO_x permit limit for H-102. This change provides for a 0.43 lb/hr increase in NO_x and accounts for higher concentrations of H₂ in the fuel gas. This proposed change was also included in the modeling analysis for the GRHC and included in the BACT analysis where H-102 and other conventional heaters were all proposed for a 0.035 lb/MMBtu BACT limit.

Note: An application assigned **MAQP #1821-35** was submitted but later withdrawn and therefore, MAQP #1821-35 does not exist. **MAQP #1821-36** replaced MAQP #1821-34. This project is still under construction.

On August 1, 2016, the Department of Environmental Quality – Air Quality Bureau (Department) received from CHS an application for modification of the Montana Air Quality Permit. CHS proposed to increase the size of the crude blending tanks originally permitted in MAQP #1821-34. Because, over time, the quality of the

primary crude oil supply to the Laurel Refinery had declined and become more variable, the utilization of process units downstream of the crude units also declined. The crude blending project was originally permitted in MAQP #1821-34. This proposed permit modification was intended to provide improved segregation of crude oils with different characteristics with the goal of enabling blending of the crude oil to allow more utilization of the existing refining process. No physical change was proposed to any other refining equipment. As a result of increased utilization of existing capacity, an increase in actual emissions was expected from the operational change. The project did not trigger the Prevention of Significant Deterioration (PSD) program because increases in actual emissions were less than PSD program thresholds. The tanks were subject to Best Available Control Technology (BACT) review through Montana's minor source permitting program. This action permitted the increase in crude oil tank sizes and reviewed the action as if the tanks were new emission sources.

In addition, CHS proposed various administrative changes to the permit to remove notification and reporting requirements associated with previous projects which have been completed. The requirements that were fulfilled and are no longer necessary were updated accordingly. **MAQP #1821-37** replaced MAQP #1821-36.

On May 11, 2017, the Department of Environmental Quality – Air Quality Bureau (Department) received from CHS an application for modification of MAQP #1821-37. CHS proposed two separate unrelated projects within the same application. The first project would have added a thermal combustor (incinerator) to control emissions from the water oil separators, dissolved flotation units, and a new wastewater surge tank. On May 25, 2017, CHS submitted a letter withdrawing this portion of the project while confirming the modification for the second project. The second project would have increased the amount of petroleum coke shipped off-site using trucks. The MAQP limited the number of trucks to 1000 trucks per year on a rolling 12-month basis. This equated to 43,500 tons based on each truck carrying 43.5 tons of petroleum coke. CHS requested to increase the allowable truck shipments to a total of 175,200 tons of coke per year determined monthly on a rolling 12-month total. This was calculated based on 5,840 trucks on a rolling 12-month basis assuming 30 tons per truckload. No physical change was proposed to any other refining equipment. As a result of increased utilization of existing capacity, an increase in actual emissions was expected from the shipping change from rail to trucks. The project did not trigger the PSD program because increases in actual emissions were less than PSD program thresholds.

In addition, CHS proposed various administrative changes to the permit to remove notification and reporting requirements associated with previous projects which were completed. An additional request by CHS was received on June 13, 2017, to include some administrative changes. Those administrative requests were incorporated to avoid an additional permit action. The requirements that were fulfilled and no longer necessary were updated and conditions for equipment no longer in service were removed. **MAQP #1821-38** replaced MAQP #1821-37.

On July 27, 2017, the Department received an application from CHS for modification of their Montana Air Quality Permit. The requested change provided for a new type of catalyst to be installed into the Ultra Low Sulfur Diesel (ULSD) reactor. The new catalyst resulted in additional hydrogen usage due to its improved

reaction rates. The additional hydrogen required would come from the new hydrogen plant which was part of MAQP #1821-36 issued on December 16, 2015, and part of the Grass Roots Hydrocracker Project (GRHC). Since the catalyst change was not possible without the additional hydrogen produced from the GRHC Project, this project was technically dependent upon the original GRHC Project. Therefore, this application updated the GRHC project to include the catalyst change-out, updated the netting analysis, and all elements required for a complete PSD application. All elements associated with PSD permit applications were followed, including public notice to Federal Land Managers. The Best Available Control Technology (BACT) analysis submitted in this revised PSD action also re-established a new construction timeframe for the GRHC Project.

The original GRHC application, received on September 16, 2015, increased the diesel production capacity at the refinery. The description of projects details from MAQP #1821-36 is included here.

The GRHC expanded diesel production with the addition of a new Hydrocracker (HC) Unit and supporting Hydrogen Plant (HRU). To accommodate the new HC, modifications were made within the existing #1 Crude Unit (#1 CRU), Mild Hydrocracker (MHC) and Fluidized Catalytic Cracking Unit (FCCU). To allow for increased product shipment by rail, the capability of the existing light product railcar loading rack was expanded. The GRHC also included the installation of two new tanks and an increase in the amine treatment capacity at the refinery.

The new HC was designed to process approximately 25,000 barrels per day of feed. The unit included three fired heaters including two identical Reactor Feed Heaters each with a design heat input capacity of 75 MMBtu/hr (HHV) and a Fractionator Feed Heater with a design heat input of 126.3 MMBtu/hr (HHV).

The new HRU included a fired heater with a design heat input capacity of 562 MMBtu/hr (HHV). The reformer type hydrogen unit was designed to provide up to 40 MMSCFD of hydrogen. In addition to supporting the increased hydrogen demand associated with the project, the new HRU also increase the reliability of the hydrogen supply at the refinery.

Although not related to the GRHC project, there was also a change made to the H-102 NO_x permit limit. This proposed change was also included in the modeling analysis for the GRHC and included in the BACT analysis where H-102 and other conventional heaters were all proposed for a 0.035 lb/MMBtu BACT limit. **MAQP #1821-39** replaced MAQP #1821-38.

On May 17, 2018, the Department received an application from CHS for modification of their Montana Air Quality Permit. The requested change proposed to increase the SO₂ ton per rolling 12-month total limit and update the SO₂ BACT limits for the Zone D Sulfur Recovery Plant (SRP). The requested changes were largely the result of unforeseen impacts from the installation of the Flare Gas Recovery System in 2015 which provided for large facility-wide reductions in SO₂ but increased the process variability in the feed gas stream exiting to the Zone D SRP tail gas treatment unit (TGTU) and upon combustion in the tail gas incinerator (TGI) resulted in higher SO₂ emissions. This process variability resulted in higher sulfur content in the Zone D SRP and upon combustion in the tailgas treatment

incinerator (TGTU) results in higher SO₂ emissions. This increase in sulfur content eliminated the operational compliance margin with the current Zone D SO₂ annual limit. Further, the requested changes addressed short-term operation during normal operation of the SRP and aligned the short-term BACT limit with short-term averaging periods and concentration consistent with the NSPS for sulfur plants, and for startups and shut-downs proposed in the new MACT standard 40 CFR 63 Subpart UUU- Refinery MACT. As these proposed changes span several projects at the refinery; the new limits were reviewed relative to previous Non-attainment Area New Source Review decisions to ensure the earlier permit determinations would not have resulted in any of those projects becoming a major modification. As part of the permit action, the daily maximum limit of 341.04 lbs SO₂ was eliminated as it is redundant with the current and maintained hourly limit of 14.21 lbs SO₂.

MAQP #1821-40 replaced MAQP #1821-39.

On September 7, 2018, the Department received an application from CHS for modification of their Montana Air Quality Permit. The requested change proposed to add a thermal combustor as a control option for the API separator and Dissolved Air and Nitrogen Flotation (DAF/DNF) vents. These will now be referred to collectively as Dissolved Gas Flotation (DGF) units. These vents were controlled by carbon adsorption and this request allowed for either the new thermal combustor or carbon to be used to control the emissions. The purpose of the request was to address the high cost of carbon replacement and provided an additional control option. CHS provided an analysis of the proposed project, and associated emissions increases and demonstrated the project was below PSD thresholds. The thermal combustor was expected to have a higher control efficiency versus carbon but each control option is approved for control. As the thermal combustor met the definition of an incinerator under MCA 75-2-103(11) MCA, CHS also provided a demonstration that the thermal combustor passed the required human health risk assessment. The request also included a number of administrative changes not specifically related to the thermal combustor.

MAQP #1821-41 replaced MAQP #1821-40.

On February 21, 2019, the Department received an application from CHS for modification of MAQP #1821-41. The requested change proposed to modify the MAQP to reflect the final scope of the Grassroots Hydrocracker Project (GRHC) and modified two limits which were established as part of the GRHC. Portions of the project which were permitted as part of the GRHC were no longer being constructed including the New Hydrocracker and therefore, conditions associated with the New Hydrocracker were removed. The Hydrogen Reformer Heater permitted as part of the GRHC was given a CO limit to specifically cover periods of startup. The current startup for the Hydrogen Reformer Heater took longer to startup and reach stable operation than the form of the current CO limit. The current limit of 41.6 lb/hr (hourly rolling 24-hr average) was not able to be achieved based on the allowable heat ramp of 50°- 90° F per hour. Recent data during startup indicated it took approximately 36 hours and therefore, requested that the form of the limit be modified to be based on an hourly rolling 36-hour average. No change in the numeric limit was requested. Related to the new Hydrocracker which was not being built, a Greenhouse Gas emissions multi-source total limit was included in the GRHC project. The CO₂e limit included the Hydrogen Reformer Heater, HC

Reactors Heaters (H-801 and H-802), HC Fractionation Heater and the FCCU. The two remaining sources were the Hydrogen Reformer Heater and the modified FCCU. The scaled back GRHC project remained subject to PSD and the revised project emissions increase was greater than 75,000 tons per year CO_{2e}, therefore CO_{2e} limits were still required for the two remaining sources. In addition, the basis of the CO_{2e} limit for the Hydrogen Reformer Heater was updated based on the procedure in 40 CFR part 98 subpart P for Hydrogen Production. This uses the 2018 actual fuel and feedstock consumption scaled to the unit's 40 MMSCFD hydrogen production and the actual carbon content and molecular weight of the refinery natural gas supply. Since the Hydrogen Reformer Heater used refinery fuel gas (RFG), potential emissions were also evaluated using the actual carbon content and molecular weight of RFG. This second alternative provided the highest potential emissions of CO_{2e}. Several minor administrative clarifications were also incorporated into the MAQP including conditions where initial source testing had been completed.

MAQP #1821-42 replaced MAQP #1821-41.

C. Current Permit Action

On March 9, 2020, the Department received an application from CHS for modification of MAQP #1821-42. The requested change proposes to modify the MAQP to provide a refinery expansion which is identified as the Multi-Unit Expansion Project, (MUE). The MUE includes projects within the #2 Crude Unit (#2 CU), Mild Hydrocracker (MHC), Delayed Coker (DCU), and Naphtha Hydrotreater (NHT). The #2CU will be modified to increase its capacity and to provide additional crude processing flexibility. The atmospheric distillation column within the #2 CU will be replaced, an existing process heater will be replaced, and the stack of another existing heater will be relocated. Additional modifications related to hydraulic capacity and heat balance will be completed. The MHC will be modified to increase its capacity. The three MHC reactors, H₂S stripper and high pressure absorber will be replaced with higher capacity equipment and a naphtha stabilizer will be added to the unit. Additional modifications related to hydraulic and heat balance will be completed. The DCU will be modified to increase its capacity. A second Coker Charge Heater (H-7502) will be installed. Additional modifications related to hydraulic capacity and heat balance will be completed. Modifications to the NHT and associated support facilities will be made to improve management of unit feed and handling of heavier hydrocarbon gases (i.e., propane, butane, etc.). The project also involves replacing existing natural gas fired Boiler 9 with a higher capacity boiler (Boiler 13). Boiler 13 will be fired with refinery fuel gas (RFG).

Unrelated MAQP updates include a review of the current NO_x limits on existing Boilers #11 and #12. This request is unrelated to the MUE project but revisits the original NO_x limits which were established in 2006 for Boiler #11 and in 2008 for Boiler #12.

Several minor administrative clarifications were also incorporated into the MAQP including clarification on reporting requirements and making sure MAQP conditions reflect planned language to be included in the CHS Title V Renewal which is currently being updated. Administrative changes include moving to electronic submittal of reports to eliminate duplicate hardcopy submittals. The planned

schedule represents a multi-year effort and must be completed in various phases which are planned to be coordinated with regularly scheduled maintenance turnaround starting in August 2020, and currently planned to be completed in 2024.

MAQP #1821-43 replaces MAQP #1821-42.

D. Process Description – Permitted Equipment

HDS Complex – CHS constructed a new desulfurization complex within the existing refinery to desulfurize the gas-oil streams from the crude, vacuum, and the propane deasphalting units in 1992. The HDS unit removes sulfur from the gas-oil feedstock before further processing by the existing FCC unit. The new HDS unit greatly reduces the sulfur content of the FCCU feeds and, thereby, reduces the regenerator sulfur oxide emissions. Sulfur oxide emissions from the FCCU occur when coke-sulfur is burned off the catalyst at the unit's regenerator. Also, the FCCU clarified oil will contain a much lower sulfur content due to the HDS unit. FCCU clarified oil, when burned throughout the refinery in various furnaces and boilers, will result in lower sulfur oxide emissions. By removing sulfur compounds from the gas-oil and other FCCU feedstocks, the HDS process effectively reduces the sulfur content of refinery finished products, such as gasoline, kerosene, and diesel fuel. Lower sulfur content in gasoline and diesel fuels results in lower sulfur oxide emissions to the atmosphere from combustion by motor vehicle engines.

Additionally, the desulfurization complex includes other process units, such as the SWS, amine, SRU, and the TGTU. The new Hydrogen Plant and new HDS unit make up the new desulfurization complex for the refinery.

CHS filed a petition for declaratory judgment, which was granted by district court, which affords confidentiality protection on all HDS process and material rates, unit and equipment capacities, and other information relating to production. These are declared to be trade secrets and are not part of the public record. Hence, the reason for not providing the barrels-per-stream-day (BPSD) capacity of the new HDS unit and other new units, save the SRU, considered in this permit application analysis.

Hydrogen Plant – This unit produces pure hydrogen from propane/natural gas and recycled hydrocarbon from the hydrodesulfurizer, which, in turn, is used in the HDS unit. The feed is first purified of sulfur and halide compounds by conversion over a cobalt/molybdenum catalyst and subsequent absorption removal. The purified hydrocarbon is mixed with steam and the whole stream is reformed over a nickel catalyst to produce hydrogen (H₂), CO, carbon dioxide (CO₂), and methane (CH₄). The CO is converted to CO₂ over an iron oxide catalyst and the total gas stream cooled and finally purified by a solid absorbent in a fixed bed or Pressure Swing Adsorption unit (PSA), (hydrogen purification unit).

The reformer heater (H-101) is utilized by the Hydrogen Plant. The design heat input rate is 123.2 MMBtu/hr; however, CHS has determined that heat inputs of up to 135.5 MMBtu/hr are necessary for short periods of time. This heater burns a combination of natural/refinery gas and recovered PSA gas. PSA gas (374Mscf/hr) supplies 85% (104.7 MMBtu/hr) of the necessary fuel requirement. The remaining 15% (18.5 MMBtu/hr) fuel requirement is supplied by natural/refinery gas (19.3Mscf/hr).

HDS Unit – A feed blend of preheated gas oils/light cycle oils from various crude units are filtered and dewatered. The feed is further heated by the reactor charge heater (H-201) and combined with a stream of hydrogen-rich treat gas and charged to the first of three possible reactors. Only two reactors (first and second) are installed and a third reactor may be added in the future. The reactors contain one or more proprietary hydro-treating catalysts, which convert combined sulfur and nitrogen in the feed into hydrogen sulfide (H_2S) and ammonia (NH_3). Effluent off the reactor flows to a hot high-pressure separator where the vapor and liquid phases separate. The vapor/liquid stream then enters the cold high-pressure separator where the phases separate. Liquid water separates from the liquid hydrocarbon phase and collects in the boot of the vessel where vapor separates from the liquids. The vapor stream from the cold high-pressure separator flows to the high-pressure absorber, where it is contacted with amine solution to remove H_2S . The vapor stream is then subjected to a water wash to remove entrained amine. Amine, rich in H_2S , is pressured from the bottom of the absorber to the amine regeneration unit. The scrubbed and washed gas leaves the top of the high-pressure absorber and passes to the recycle cylinders of the make-up/recycle gas compressors. A portion of the discharge gas from these compressor cylinders is used as quench to control the inlet temperatures of the second reactor (and possibly a third reactor in the future).

H_2 from the Hydrogen Plant flows into the make-up/recycle gas unit section. The H_2 is compressed in the two-stage make-up cylinders of the make-up/recycle gas compressors and then mixed with the recycle gas stream. The combined gas (treat gas) recovers heat from the hot high-pressure separator and is then injected into the preheated oil feed at the inlet of the heat recovery exchangers.

In the fractionation section of the HDS unit, hot liquid from the hot high-pressure separator is mixed with cold liquid from the cold high-pressure separator and the combined stream is flashed into the H_2S stripper tower. The heat in the tower feed and steam stripping separates an off-gas product from the feed with essentially complete removal of H_2S from the bottom product. This off-gas product leaves the H_2S stripper overhead drum and flows to the amine unit for recovery of sulfur. The bottom product from the H_2S stripper is heated in the fractionator feed heater (H-202) and is charged to the flash zone of the fractionator. In the fractionator tower and associated diesel stripper tower, H_2S stripper bottoms are separated into a naphtha overhead product, a diesel stripper stream product, and a bottom product of FCC feed. Separation is achieved by heat in the feed, steam stripping of the bottom product, and reboiling of the diesel product.

The naphtha product is pumped from the fractionator overhead drum to intermediate storage. The diesel and bottoms desulfurized gas-oil (FCC feed) products are also pumped to intermediate storage. A new wash water and sour water system will accompany the reaction/separation section of the HDS unit. Water is pumped from the wash water surge tank and injected into the inlet of the high-pressure separator vapor condenser to remove salts and into the high-pressure absorber circulating water system to remove amine. Water injected to the hot high-pressure separator vapor condenser produces sour water, which accumulates in the water boot of the cold/high-pressure separator. This sour water is pressured to the sour water flash drum. Additional sour water is produced from stripping steam and

heater injection steam and accumulates in the water boots of the H₂S stripper overhead drum and the fractionator overhead drum. Other accumulations from sour water sources, such as knock-out drums, are also sent up to the sour water flash drum. The sour water is pressured from the sour water flash drum and sent to the sour water storage tank.

A reactor charge heater (H-201) and fractionator feed heater (H-202) is utilized by the HDS unit. H-201 design heat input rate is 37.7 MMBtu/hr. Once the HDS reactors are at operating temperature, the process is exothermic. As a result, H-201 firing rates are reduced. For purposes of this application, the worst case assumption is made that H-201 always operates at 80% for design (30.2 MMBtu/hr and 31.2 Mscf/hr). H-202 heat input design rate is 27.2 MMBtu/hr. Similar to H-201, once the HDS reactors are at operating temperature, the process is exothermic and produces sufficient heat to sustain the reaction temperature. Excess heat is recovered and transferred to the fractionator feed which reduces the need for the fractionator feed heater. For purposes of this application, the worst case assumption is made that H-202 operates at 75% of full design capacity (20.4 MMBtu/hr and 21.3 Mscf/hr).

Amine Unit – A solution of amine (nitrogen-containing organic compounds) in water removes H₂S from two refinery gas streams. The new amine unit will not process sour refinery fuel gas since this operation is to be handled by the existing refinery amine unit, except for amine unit start-up operations.

Amine temperature is controlled to assure that no hydrocarbon condensation occurs in the absorber tower. A large flash tank with a charcoal filter is used to remove any dissolved hydrocarbons. The flash vapor flows to the TGTU for sulfur recovery. Also from the flash tank, the rich amine flows through the rich/lean exchanger where it is heated and sent to the still regenerator. The regenerator is heat controlled. The clean amine level is controlled, and the amine cooler stream is sent to a surge tank with a gas blanket. Lean low-pressure and high-pressure streams are pumped from the surge tank to their respective contactors. H₂S in the overhead gas from the amine still accumulator are directed to the new SRU.

Sour Water Stripper – As part of MAQP 1821-33, CHS proposed a new two stage Sour Water Stripper. The New Zone E SWS proposed has a capacity of approximately 360 gallons per minute.

The Sour Water Stripper removes ammonia, reduced sulfur compounds, and small amounts of hydrocarbons from the sour water prior to directing the water to wastewater treatment or reuse. The sour water is to be treated in two stages which creates two vent streams. One vent stream, rich in reduced sulfur compounds, is to be treated at the Sulfur Recovery Plant. The other vent stream, rich in ammonia, is to be sent to a caustic-based scrubber to remove remaining reduced sulfur compounds and then incinerated. The incinerator is to be equipped with Selective Catalytic Reduction technology to reduce the amount of NO_x emitted from combustion of the ammonia.

Sulfur Recovery Plant – The SRU is designed as a dual operation facility. The SRU has two different modes of operation.

Mode I - Standard Straight Through Operation is where the unit operates as a standard three-bed Claus unit. The Claus operation consists of a sulfur reaction furnace designed to sufficiently burn (oxidize) incoming acid gas (H_2S) to SO_2 , to form water vapor and elemental sulfur. SO_2 further reacts with H_2S to form more sulfur and water vapor. This is accomplished over three sulfur reactor catalyst beds and four condensers. Following the final reactor and condensing phase, the tail gas from the SRU is directed to the TGTU where additional sulfur treating occurs to further enhance recovery.

The new SRU has a design input rate of 79.18 short tons of sulfur per day (70.69 long ton/day) from three refinery feed streams. The overall efficiency of Mode I operation is 97.0%. This figure does not include additional sulfur recovery at the TGTU. Mode II - Sub-Dew Point Operation utilizes the same Claus reaction and front-end operation, except the second and third catalyst beds are alternated as sub-dew point reactors. The gas flow is switched between the two beds. When a bed is in the last position, the inlet temperature is lowered, which allows further completion of the H_2S - SO_2 reaction and, thereby, recovering more sulfur. The sulfur produced condenses, due to the lower temperature, and is absorbed by the catalyst. After 24 hours of absorbing sulfur, the switching valve directs the gas flow from the third reactor to the second reactor and from reactor #2 to reactor #3. The cold bed is then heated by being diverted to the hot position and all the absorbed sulfur is vaporized off, condensed and collected. The former hot bed is then cooled and utilized as the sub-dew point reactor for a period of 24 hours. The system cycles on a daily basis. The overall efficiency of Mode II operation is 98.24%. This figure does not include additional sulfur recovery at the TGTU. The advantage to two different modes of operation is for those times when the TGTU is not operating. The final heater (E-407) is used during the standard Claus unit operation; but, during the sub-dew point mode, it is blocked to prevent sulfur accumulation.

Tail Gas Treating Unit – The TGTU converts all sulfur compounds to H_2S so they can be removed and recycled back to the SRU for reprocessing. This process is accomplished by catalytically hydrogenating the Claus unit effluent in a reactor bed. From the reactor, the vapor is cooled in a quench tower before entering the unit's amine contactor. The hot vapors enter the bottom of the quench tower and contact water coming down the tower. The water is sent through a cooler exchanger and recycled in the tower. Excess water is drawn off and sent to the new sour water storage system. The cooled-off gas enters the bottom of the unit's amine contactor where H_2S is removed prior to final incineration. The TGTU's amine contactor and regeneration system are separate from the other two amine units previously mentioned. This design prevents cross-contamination of amine solutions. The off-gas from the TGTU amine contactor containing residual H_2S is sent to the sulfur plant incinerator. The concentrated H_2S stream is directed to the SRU sulfur reaction furnace, which converts the H_2S to SO_2 , which recycles through the Claus process. The efficiency of the TGTU for sulfur removal is 99.46%. The TGTU adds additional sulfur recovery efficiency to the sulfur plant. The overall efficiency for sulfur removal for the SRU, plus TGTU, is 99.96%.

The sulfur plant incinerator (INC-401) is designed to burn any H_2S and other substances that make it past the SRU and TGTU. Also, exhaust gas from reheater E-407 (operated during Mode I) at the SRU is vented to the sulfur plant incinerator. The design heat input rate for reheater E-407 is 1.0 MMBtu/hr and is fired by

natural/refinery gas. The design heat input rate for INC-401 is 3.8 MMBtu/hr. Therefore, these two fuel-burning devices, together, will fire a potential 5.0 Mscf/hr of fuel gas (4.8 total MMBtu/hr).

The overhead gas (H_2S , NH_3) from the SWS unit is treated by the SRU. SWS gas from the existing unit is currently incinerated at the FCC-CO boiler and results in significant emissions of SO_2 and NO_x . This refinery activity and resultant emissions will cease, contemporaneously, with the new HDS operation. Also, the sulfur feed to the existing refinery Claus SRU will be greatly diminished. This should result in significant SO_2 emission reductions, which have not been quantified.

Ultra Low Sulfur Diesel Unit and Hydrogen Plant – The ULSD Unit was designed to meet the new sulfur standards for highway diesel fuel as mandated through the national sulfur control program in 40 CFR Parts 69, 80, and 86. CHS shut down the existing MDU and replaced it with the ULSD Unit, to produce ultra low sulfur diesel and other fuels. At installation, the ULSD Unit was designed to handle the existing MDU process feeds of 21,000 bpd including; raw diesel from #1 and #2 Crude Units, hydrotreated diesel from the Gas Oil Hydrotreater, light cycle oil from the FCCU, and burner fuel from the #1 and #2 Crude Units. The feed streams are processed into several product streams; finished diesel, finished #1 burner fuel, and raw naphtha. After the delayed Coker project in 2007, the available feed processed by the ULSD unit is expected to increase to 24,000 bpd.

These products are stored in existing tanks dedicated to similar products from the MDU. Seven storage tanks were modified as a result of the original ULSD Unit project.

CHS's existing Hydrogen Plant and the proposed Hydrogen Plant would supply hydrogen for hydrotreatment. These units catalytically reform a heated propane/natural gas and steam mixture into hydrogen and carbon dioxide then purify the hydrogen steam for use in the ULSD Unit. Existing plant sources also supply steam and amine for the ULSD Unit.

Sour water produced in the ULSD Unit will be managed by existing equipment, including a sour water storage tank and a sour water stripper that vents to SRU #400. Fuel gas produced in the unit will be treated and distributed within the plant fuel gas system. Oily process wastewater and storm water from process areas managed in existing systems will be treated in the existing plant wastewater treatment plant.

Zone A's TGTU for SRU #1 and #2 Trains – The SRUs convert H_2S from various units within the refinery into molten elemental sulfur. The SRU process consists of two parallel trains (SRU #1 and SRU #2 trains) that each include thermal and catalytic sections that convert the H_2S and SO_2 into sulfur. In each train, the process gas exits the catalytic reactors and enters a condenser where sulfur is recovered and is gravity fed into the sulfur pits. Process gas from the condensers is then sent to the TGTU for additional sulfur removal. The TGTU is an amine-type H_2S recovery and recycle TGTU. The TGTU utilizes an in-line tail gas heater (TGTU-AUX-1), which also generates hydrogen from reducing gases that reduce the SO_2 in the tail gas to H_2S . After passing through the quench tower, the stream enters an amine absorber where H_2S is selectively absorbed. The off-gas passes to the SRU-AUX-4, where it is

incinerated to convert remaining H₂S to SO₂ before venting to atmosphere. The rich amine leaving the absorber is regenerated in the tail gas regenerator, and the H₂S recovered is routed back to the front of the SRU unit. The lean amine is routed to a new MDEA surge tank (TGTU-VSSL-6). The efficiency of the TGTU for sulfur removal is 98.93%. The TGTU adds additional sulfur recovery efficiency to the sulfur plant. The overall efficiency for sulfur removal for the SRU, plus TGTU, plus the SRU-AUX-4, is nearly 100%.

The SRU-AUX-4 is designed to burn any H₂S and other substances that make it past the SRU and TGTU. Also, exhaust gas from the SRU-AUX-1 is vented to SRU-AUX-4. The design heat input rate for TGTU-AUX-1 is 4.17 MMBtu/hr and the unit is fired by natural/refinery fuel gas. The design heat input rate for SRU-AUX-4 is 10.85 MMBtu/hr and the unit is fired on refinery fuel gas. Therefore, these two fuel-burning devices, together, will potentially use 18.55 Mscf/hr of natural and refinery fuel gas (15.02 total MMBtu/hr).

Delayed Coker Unit – The delayed coker unit is designed to process 15,000 bpd of a residual asphalt stream (crude vacuum distillation bottoms). Through the delayed coking process, the unit will produce 800 short tons per day of a solid petroleum coke product and various quantities of other liquid and gaseous petroleum fractions that will be further processed in other refinery units. When integrated into other refinery operations, it is expected that the coker will result in an approximate 75% decrease in asphalt production and a 10-15% increase in gasoline and diesel production. Although the delayed coker project and other projects described in Permit Application #1821-13 will result in a shift in the type of products that will be made at the refinery, there will not be a change to the refinery's 58,000 bpd capacity, and actual crude processing rates are not expected to increase.

Some of the major equipment items in the delayed coker unit include: a new 160.9 MMBtu-high heating value (HHV)/hr Coker Charge Heater (H-7501), a new Coke Storage Area and Solids Handling Equipment to store and transfer the 800 short tons per day of coke product to rail cars for shipment; a new Coker Flare used exclusively to control emissions during start-up, shutdown, and malfunctions (no continuous vents will be flared); and a new coker amine unit and a Zone E (previously called Coker) SRU/TGTU/TGI, which is designed to process 70.6 long tons per day of sulfur. There will be emissions from a Coker Unit Oily Water Sewer and Cooling Tower.

Main Refinery Flare and Flare Gas Treatment and Recovery System – The Main Refinery Flare combusts flammable, toxic, and corrosive vapors to less objectionable compounds. Vent gases created as part of normal operations of a refinery, as well as emissions associated with startup, shutdown, and malfunction of refinery equipment, if vented uncontrolled, would provide for a significantly higher risk to human health and the environment than as occurs in being flared. The Main Refinery Flare provides an important pollution control and safety function during both emergency and routine operations. Emergency flaring may include flaring from pressure relief flows or emergency depressurization of process equipment. Venting of gases may be required for maintenance or as a part of startup or shutdown operations. Relatively continuous generation of vent gases are created from, for example, captured gas seal leakages from various equipment or as a necessary part of pressure control.

The Replacement Refinery Flare permitted as part of MAQP #1821-33 is expected to have an upset capacity of approximately 662,000 pounds per hour of flare gas for the maximum relief scenario, and a smokeless capacity of approximately 140,000 pounds per hour of vent gas. A Flare Gas Treatment and Recovery System is to be installed, where recovered vent gases will be treated via an amine treater to remove reduced sulfur compounds and send the gas to be burned in refinery fuel gas burning equipment instead of being flared. The Flare Gas Treatment and Recovery System will have a minimum capacity of 77,000 standard cubic feet per minute on an annualized basis. No change to the amount of gases created as a part of normal operations was permitted in MAQP #1821-33.

Under the Grassroots Hydrocracker Project (MAQP 1821-36) the following process changes are were planned. The project description has been updated to reflect the final scope of the project (MAQP #1821-42).

New Hydrocracker (Hydrocracker #2) planned as part of MAQP #1821-36.

The GRHC includes scope originally included the construction of a second hydrocracker (HC) at the refinery. The addition of the new hydrocracker has since been canceled.

New Hydrogen Plant (Hydrogen Plant #3) after GRHC completed as part of MAQP #1821-36.

The GRHC included the construction of a new hydrogen plant (Hydrogen Plant #3) that converts natural gas, refinery fuel gas, or other process gases to high purity hydrogen using a standard steam methane reforming process. The new hydrogen plant is capable of producing approximately 40 MMSCF/day of hydrogen. The new hydrogen plant includes a Reformer Heater with a maximum design firing capacity of 562 MMBtu-HHV/hr. The heater is fired with natural gas, refinery fuel gas, and PSA tail gas generated within the hydrogen plant. In the reforming process, the feed stream is mixed with a relatively small volume of recycled hydrogen and preheated in a coil located in the Reformer Heater stack. The mixture is then fed to a hydrogenation reactor to convert organic sulfur compounds to H₂S. The gas is then directed to a series of absorbers where the sulfur compounds are removed. Following feed purification, the feed gas is mixed with steam and preheated in a coil located in the convection section of the Reformer Heater. The preheated steam-hydrocarbon mixture is then passed through the radiant section of the Reformer Heater. The hydrocarbons are reformed over a catalyst to produce H₂, CO, CO₂ and CH₄. The process gas exiting the Reformer is cooled and the heat is recovered resulting in the generation of high-pressure steam. To increase the overall energy efficiency of the plant, carbon monoxide in the process gas is then removed by reaction with steam to form hydrogen and carbon dioxide. This reaction occurs in the high temperature Shift Converter where CO reacts exothermically over a catalyst. The gas is cooled resulting in the generation of additional high pressure steam. The mixture of condensate and process gas is then cooled further and separated. The condensate is recycled and retreated as boiler feed water and the process gas is routed to the Pressure Swing Absorber (PSA).

The PSA contains multiple fixed beds of solid absorbent used to remove impurities, such as CO₂, to produce high purity hydrogen (99.9 vol %). When an absorbent bed becomes saturated, it is regenerated by depressurizing and purging it with product hydrogen. This purge gas, PSA tail gas, consisting of CO₂, CO, CH₄, N₂, and H₂, will be used in the Reformer Heater as its primary fuel. It should be noted that with the exception of startup, PSA tail gas is anticipated to supply approximately 55 percent of the heat input (i.e., MMBtu/hr) to the reformer. The supplemental fuel will be natural gas or RFG. Only natural gas or RFG will be used during startup.

#1 Crude Unit Modifications GRHC completed as part of MAQP #1821-36.

The CHS refinery has two Crude Units, the #1 and #2 Crude Units. At each of the Crude Units a two-step distillation process is used to fractionate the crude into the various intermediate product streams described above. Crude oil from storage is first preheated and then treated in a desalting process to remove the solids, salts, and water found in crude oil. Downstream of the desalter, the crude oil is heated in one of two process heaters, #1 Crude Unit Preheater (CV-HTR-1) and #1 Crude Unit Main Heater (CV-HTR-2), prior to the Atmospheric Column where the crude is distilled at atmospheric pressure. In the Atmospheric Column the distillate vapors move up the column counter current to a cooler liquid stream. As the heavier hydrocarbons are being condensed from the vapors, various distillate streams, including gas oil, raw #2 diesel and raw burner fuel (i.e., #1 diesel), are drawn off the column at tray locations in relation to the temperature inside the tower. As noted above, these distillate streams are processed in downstream units (i.e., MHC and ULSD). The column overhead stream is cooled, condensed and routed to the Naphtha Hydrotreating Unit (NHT). A gaseous stream is also recovered from the overhead of the Atmospheric Column for treatment and subsequent use in the refinery fuel gas system.

The intermediate stream exiting the bottom of the Atmospheric Column is directed to the #1 Crude Unit Vacuum Heater (CV-HTR-4) where it is heated and routed to the Vacuum Column. The Vacuum Column operates in a similar fashion to the Atmospheric Column except that it operates under a vacuum so that distillation can be carried out at lower temperatures. The streams recovered from the Vacuum Column include gas oils that are processed in the MHC and the bottom stream (i.e., asphalt) that is either sold as product or processed in the refinery's Delayed Coker Unit. A distillate stream can also be recovered from the Vacuum Column and processed at the ULSD.

As part of the GRHC physical changes were made at the #1 Crude Unit to optimize and improve the operation of the unit for a wider range of crude types. In certain operating scenarios, the unit may be able to process approximately 10% more crude than its current capacity. To accomplish this, the project included the following physical changes:

- Heat exchange trains in the unit were modified.
- The vacuum processing systems were modified.
- A number of pumps and associated piping components were modified or replaced.

Mild Hydrocracker (MHC) after GRHC completed as part of MAQP #1821-36.

The existing MHC Unit currently processes gas oils from the two Crude Units and the Delayed Coker Unit. The GRHC scope included the mechanical and process control modifications required to process a range of new external feed sources in the unit. The capacity of the MHC Unit will not change as a result of the project.

FCCU Modifications after GRHC completed as part of MAQP #1821-36.

The Fluidized Catalytic Cracking Unit (FCCU) is used to convert gas oil into lighter, more valuable materials, including gasoline and fuel oils. At the FCCU preheated feed is injected into the riser where it is vaporized and cracked into smaller molecules by contact and mixing the feed with very hot powdered catalyst from the catalyst Regenerator. The hydrocarbon vapors fluidize the powdered catalyst and the mixture of hydrocarbon vapors and catalyst flows upward in the riser to the Reactor.

Within the FCCU Reactor, cyclones are used to separate the cracked product vapors from the “spent catalyst.” The spent catalyst flows downward through a steam stripping section to remove any hydrocarbon from the spent catalyst prior to entering the catalyst Regenerator. The cracked hydrocarbon is then directed to the FCCU distillation process where the cracked products are separated into various intermediate product cuts. The majority of the product is a refinery gasoline component. Light cycle oil is also produced, which is typically processed through the ULSD Unit. The heaviest stream produced by the FCCU, clarified oil, is typically sold as fuel oil. Alternatively, clarified oil can be directed to the Delayed Coker Unit for additional processing or recycled back to the riser.

As a byproduct of the cracking process, carbon/coke deposits on the catalyst. As the carbon is deposited on the catalyst surface, it becomes inactive, or spent. As a result, catalyst is continuously regenerated by burning off the deposited coke in the FCCU Regenerator. The combustion of the coke is exothermic and produces a large amount of heat that is necessary for the vaporization of the feed and the endothermic cracking reactions that take place in the Riser. This catalyst regeneration process gives off primarily CO₂ and water along with parts per million levels of CO, NO_x, SO₂, VOC, and particulates. CHS utilizes an ESP to control FCCU Regenerator particulate emissions and catalyst additives to control CO and SO₂ emissions. Maintaining a high enough temperature within the Regenerator is key to minimizing CO emissions.

At the FCCU, the GRHC will included the following modifications such that a safe and stable operation can be maintained at reduced FCCU feed rates:

- Replaced the spent catalyst stripper with a new design to be more efficient at a lower operating rate.
- Replaced the primary and secondary reactor cyclones with a new design to accommodate lower operating rates.
- Replaced the regenerator cyclones with a new design to reduce catalyst losses.

- Replaced the regenerator air grid to provide a stable operation at lower rates.
- Replaced the regenerator stand pipe. The new design will not result in the ability to circulate more catalyst than is currently possible.
- Replace the spent catalyst distributor within the regenerator. The new design will help stabilize CO emissions from the catalyst regeneration process.

Finally, the regenerator's air preheater was replaced because it had reached the end of its mechanical life. This natural gas direct-fired heater is used during the unit startup process to achieve the required operating temperature in the regenerator. It is also used following unit upsets or malfunctions to help return the unit to normal operations. Because the air preheater is a direct fired heater, its combustion emissions exhaust into the FCCU regenerator along with the heated air.

Light Product Railcar Loading after GRHC completed as part of MAQP #1821-36.

The CHS refinery currently ships product by truck, railcar, and pipeline. The existing railcar light product loading rack has six loading spots that are each capable of loading both gasoline and diesel product. Within the current operating philosophy, the existing facility is capable of loading a total of 12 railcars per day. The loading rack has a dedicated vapor combustion unit (VCU) that is designed to process vapors associated with a maximum loading rate of 2000 gallons per minute (gpm) of gasoline.

The GRHC included the construction of one additional loading spot at the railcar light product loading rack. The existing VCU is capable of processing the vapors associated with the increased loading capability without modification.

Amine Treatment Elements after GRHC completed as part of MAQP #1821-36.

Within a petroleum refinery, the removal of sulfur compounds from crude oil is required to meet product specifications. One of the processes used is a two-step amine treatment process used to remove sulfur compounds from process gases. In the first step, sulfur rich ("sour") gas streams are routed to an Absorber. In the absorber, H₂S is removed by contacting down flowing "lean" amine (Methyldiethanolamine or MDEA) with up flowing sour process gases. The "sweet" process gases that exit the absorber are then used as refinery fuel gas at various combustion sources or are reused in the process. In the second step, the sulfur containing ("rich") amine is routed to a Regenerator. In the regenerator, H₂S is removed from the amine in a column through contact with steam generated by reboiling. The recovered "lean" amine is recycled for reuse in the absorber. The overhead stream is separated into gaseous and liquid streams. The gaseous stream ("acid gas" - primarily H₂S) is routed to a sulfur recovery unit. The liquid stream (i.e., water) is recycled back to the amine regenerator with a small volume being purged to a sour water stripper.

The GRHC project includes the installation of additional amine treatment equipment and may modify existing treatment equipment if the existing equipment's capacity is determined to be insufficient.

Storage Tanks After GRHC Completed as part of MAQP #1821-36.

As part of the GRHC two new asphalt tanks will be constructed. Each fixed roof tank will have a capacity of 100,000 barrels and will be equipped with a steam coil. Additionally, existing Tank 114 will be changed from asphalt to diesel product service.

MUE Project and Other MAQP Changes as part of MAQP #1821-43

#2 CU Vacuum Heater (005HT0002) (New)
 Coker Charge Heater (H-7502) (New)
 Boiler #13 (New)
 #2 CU Refinery Equipment (Modified)
 MHC Refinery Equipment (Modified)
 DCU Refinery Equipment (Modified)
 NHT Refinery Equipment (Modified)
 Boiler Area Refinery Equipment (Modified)
 All Other Equipment under MAQP #1821-43 was Project Affected

#2 CU Vacuum Heater (005HT0002) replaces existing #2 CU Vacuum Heater (2CV-HTR-2)
 Boiler # 9 will be permanently shut down

E. Response to Public Comments (None received)

F. Response to CHS Comments

Reference to PD	Comment	Department Response
I.B (page 3), permit analysis (PA) (page 39)	In the first sentence on page 3 of the Current Permit Action discussion, the sentence should be updated to clarify that boiler 11 was permitted in 2006 and boiler 12 was permitted in 2008. The same comment applies to the Current Permit Action discussion in the permit analysis.	Updated
I.B (page 3)	In the final paragraph of the Current Permit Action discussion, we suggest the following update for clarity: "Both of the emitting units associated with these stack changes will not see a change in potential to emit emission increases as they are limited in their current rates by their burner rates design capacity and any change in pressure drop in the exhaust stack does not change their potential to emit."	Updated
I.B (page 3), PA (page 40)	We suggest the following update to the last sentence of the Current Permit Action discussion: "...and is planned to be completed in various phases which will be coordinated with regularly scheduled maintenance turnarounds starting in August 2020, and wrapping up currently planned to be completed in 2024."	Updated

IV.B (page 11)	As requested in our application, applicability of 40 CFR 63 subpart CC was added to this section of the permit. For consistency with other areas of the MAQP, we suggest that you consider reformatting the addition of the requirements to be similar with what is included in Section XI.B. 1 and 2 (page 36).	Updated
IV.F.1 (page 14), IX.G (page 31), XI.F.3 (page 41)	These conditions include the testing requirements for the three refinery SRU incinerator stacks. Because the emissions units are similar in size and service, we request that the stack testing frequency of all three be the same. Our suggestion is that the demonstration of compliance with the SO ₂ limits (above and beyond the CEM) be completed once every three years as proposed and a stack test to demonstrate compliance with the NO _x limit be required once every six years. The six year test frequency is proposed because the incinerators are small combustion units (~ 10 MMBtu/hr) and this schedule will coincide with the SO ₂ testing schedule.	Updated
V.D. (page 18)	As part of the comprehensive review of existing stack testing requirements being completed with this permit modification, we request that the routine VOC testing required on Boiler 11 be replaced with the requirement to complete testing “as requested by the Department”. Other than the two loading rack vapor combustion units, it is the only combustion source at the refinery that requires routine VOC testing. Test results have consistently shown VOC emission rates significantly below half of the permit limits.	Believe this should be for Boiler #10. Updated
VI.E.3 (page 22) and XIII.E.4 (page 47)	For consistency with the refinery’s operating permit, we suggest that these loading rack vapor combustion unit (VCU) stack testing requirements be updated to indicate that NO _x and CO testing is required “as requested by the Department”.	Updated
VIII.E.7 (page 27)	In the preliminary determination, the required frequency of stack testing for the H-901 and H-902 process heaters was reduced. As a result, we recommend the last sentence of this condition be reworded, as follows: “Compliance with the H-901 and H-902 CO emission limits shall be determined from emissions factors generated from the annual most recent CO stack test testing requirement... ”	Updated
VIII.H.2.a (page 28)	We request that this CO emission reporting requirement for the H-901 and H-902 heaters be removed. The heaters no longer have short term CO limits and reporting hourly lb/hr data on emissions units without CEMs is not appropriate.	Agreed. Removed
X.F.1 (page 35)	As part of the comprehensive review of existing stack testing requirements being completed with this permit modification, we request that the frequency of the routine PM testing required on FCC Regenerator stack be reduced from annual to once every three years. Annual test results have consistently shown PM emission rates well below permit limits.	Modified
XI. (page 36)	This section of the permit includes conditions that were established when the Delayed Coker project was originally permitted (initial permit MAQP 1821-13). Because the new MUE project Section XXV includes requirements for a second Coker Charge Heater, we suggest that reference to MAQP 1821-13 or the original coker project be made to the Section XI heading/description as a way to note that not all Delayed Coker unit requirements are included in this section.	Clarified
XI.A.	For consistency with the refinery’s operating permit, we suggest that applicability of NSPS subpart Ja to the Coker unit flare be added to this section of the permit.	Updated

XI.D.3 (page 38)	This condition is related to the Coker unit flare. For consistency with the updates currently being made to the operating permit, we suggest that this condition be replaced with the relatively new flare requirements of 40 CFR 63 subpart CC, specifically 63.670 (requirements for flare control devices) and 63.671 (requirements for flare monitoring systems). As noted at 63.640(s), after January 30, 2019, flares that are subject to the provisions of 40 CFR 60.18 or 63.11 are required to comply only with the provisions of subpart CC.	Updated
XI.D.9 (page 40)	This condition includes requirements related to the coke drum steam vent. To be consistent with the updates currently being made to the refinery's operating permit, we suggest that the new 40 CFR 63 subpart CC requirements related to the vent be added to the permit, as follows: "CHS shall depressure each coke drum to a closed blowdown system until either: · The coke drum average pressure is 2 psig or less, determined on a rolling 60-event average; or · The coke drum average vessel temperature is 220 degrees Fahrenheit or less, determined on a rolling 60-event average."	Updated
XI.E.5 (page 41)	We suggest this coke drum steam vent monitoring condition be revised to reference the requirements of 40 CFR 63.657.	Updated
XII.F (page 44)	Since Boiler 11 is subject to the NOx limit in NSPS subpart Db, we suggest that a compliance demonstration requirement similar to what is included for Boilers 10 (V.E.2) and 12 (XIV.D.4) be added to this section of the permit.	Updated
XIV.F (page 49)	Conditions F.1 and F.3 seem to be duplicate compliance demonstration conditions. We suggest that one or the other be removed from the permit.	Removed F.1
XV.G.2.a (page 53)	This is a NOx emission reporting requirement for the Platformer Splitter Reboiler. Because this heater doesn't have CEMs, compliance with the lb/hr limit at XV.D.2.b is demonstrated during a routine stack test. As such, it is not appropriate to calculate (or report) emissions from this heater on an hourly basis. For this reason, we request that this reporting requirement be removed. Note that this request was included on page 9-4 of the permit application and may have been overlooked.	Removed
XX.A. (page 58)	This section includes requirements for the main refinery flare. For consistency with the updates currently being made to the refinery's operating permit, we suggest that applicability to the relatively new 40 CFR 63 subpart CC flare requirements be incorporated into the permit. As noted at 63.640(s), after January 30, 2019, flares that are subject to the provisions of 40 CFR 60.18 or 63.11 are required to comply only with the provisions of subpart CC. Several existing conditions in this section of the permit have references to 60.18 and/or 63.11.	Updated
XX.A.3 (page 58)	This is the visible emissions condition for the main refinery flare. If reference to the new 40 CFR 63 subpart CC requirements for flares are incorporated into the permit, this condition can be removed as visible emissions are discussed in 63.670.	Removed
XXV.A.3 (page 67)	We suggest the following clarification to the final sentence of this condition: "The MUE Project does not result in additional applicability to subpart GGG. The #2 Crude Unit, DCU and NHT are were already subject to subpart GGG requirements and is noted here for information purposes."	Updated

XXV.A.4 (page 67)	We suggest the following clarification to the final sentence of this condition: “The MUE Project does not result in additional applicability to subpart GGGa. The MHC and RFG piping to the refinery steam generating boilers are were already subject to the subpart GGGa requirements and is noted here for information purposes.”	Updated
XXV. (page 67)	In addition to the two LDAR conditions above (A.3 and A.4), a condition should be included in the permit that identifies “an LDAR program meeting the requirements of NSPS subpart GGGa” as BACT for the MUE. As a result, upon completion of the MUE projects within the #2 Crude Unit, DCU and NHT, these process units will be required to follow a subpart GGGa program rather than a subpart GGG program. We also suggest you consider adding a note for clarification at condition XI.A.3 (i.e., the current NSPS GGG condition for the DCU and NHT).	Added new section "I"
XXV.A.5 (page 67)	For clarity, we suggest that this NSPS subpart Ja applicability condition be updated to indicate applicability by affected facility. The Coker Charge Heater (H-7502) is subject to the process heater NOx and fuel gas H2S requirements. The #2 CU Vacuum Heater (05H0002) and Boiler #13 are subject to the fuel gas H2S requirements.	Updated
XXV.B.2 (page 68)	Because all of the existing process units included in the MUE are already subject to the requirements of 40 CFR 63 subpart CC which is noted in other areas of the MAQP and/or operating permit, we suggest the following simplification of this condition: “Subpart CC: NESHA P from Petroleum Refineries shall apply to, applicable components of the MUE project with the potential for greater than five percent weight HAP, these include new heat exchangers affected sources or the collection of emission points as defined in this subpart.”	Updated
XXV.D (page 68)	In this general CEMs condition, reference to “60.100a – 60.108a” can be deleted because it is a duplicate of the “NSPS Ja” reference.	Updated
XXV.E.1.b (page 68)	This NOx condition for the new #2 CU Vacuum Heater should be updated to indicate the numerical limit applies to NOx.	Updated
XXV.E.1.c (page 68)	For clarity, we suggest the CO condition for the new #2 Vacuum Heater be reworded, as follows: “CO emissions from the #2 CU Vacuum Heater (005HT0002) shall be minimized by utilizing utilize proper design and good combustion practices, and not exceed 1.05 lb/hr as demonstrated with EPA Federal Reference Method 10.”	Updated
XXV.E.1.d (page 68)	For clarity, we suggest the VOC condition for the #2 CU Vacuum Heater be reworded, as follows: “VOC emissions from the #2 CU Vacuum Heater (005HT0002) shall be minimized utilize by utilizing proper design and good combustion practices, and shall be demonstrated by compliance with the CO emission limit and completion of the preventative tune-ups required by per 40 CFR 63 Subpart DDDDD.”	Updated

XXV.E.1.e (page 68)	For clarity, we suggest the PM ₁₀ /PM _{2.5} condition for the #2 CU Vacuum Heater be reworded, as follows: “CHS The #2 CU Vacuum Heater (005HT0002) shall utilize proper design and good combustion practices and complete the preventative tune-ups required by 40 CFR 63 Subpart DDDDD to minimize PM ₁₀ /PM _{2.5} emissions at the #2 CU Vacuum Heater (005HT0002) and the preventative tune-ups per 40 CFR 63 Subpart DDDDD.”	Updated
XXV.E.1.f.ii (page 69)	For clarity, we suggest adding the word “Completing” to the beginning of this condition.	Updated
XXV.E.2.b (page 69)	In this NOx condition for the Coker Charge Heater (H-7502), we suggest that the numerical limit be clarified to indicate it is a NOx limit. Additionally, we suggest that the reference to the CEMs be removed as it discussed in Section XXV.G. If the CEMs references remain in this condition, the O ₂ CEMs should not be included.	Updated
XXV.E.2.c (page 69)	In the comment below this NSPS subpart Ja NOx condition, we suggest the following edit for clarification: “CHS may also be eligible to submit choose to propose an alternate compliance demonstration (limit)...”	Updated
XXV.E.2.d (page 69)	For clarity, we suggest the CO condition for the new Coker Charge Heater (H-7502) be reworded, as follows: “CO emissions from the Coker Charge Heater (H-7502) shall be minimized by utilizing utilize proper design and good combustion practices, and not exceed 6.43 lb/hr following as demonstrated with EPA Federal Reference Method 10.”	Updated
XXV.E.2.e (page 69)	For clarity, we suggest the VOC condition for the Coker Charge Heater (H-7502) be reworded, as follows: “VOC emissions from the Coker Charge Heater (H-7502) shall be minimized utilize by utilizing proper design and good combustion practices, and shall be demonstrated by compliance with the CO emission limit and completion of the preventative tune-ups required by per 40 CFR 63 Subpart DDDDD.”	Updated
XXV.E.2.f (page 69)	For clarity, we suggest the PM ₁₀ /PM _{2.5} condition for the Coker Charge Heater (H-7502) be reworded, as follows: “CHS The Coker Charge Heater (H-7502) shall utilize proper design and good combustion practices and complete the preventative tune-ups required by 40 CFR 63 Subpart DDDDD to minimize PM ₁₀ /PM _{2.5} emissions at the Coker Charge Heater (H-7502) and the preventative tune-ups per 40 CFR 63 Subpart DDDDD.”	Updated
XXV.E.2.g.ii (page 70)	For clarity, we suggest adding the word “Completing” to the beginning of this condition.	Updated
XXV.E.3 (page 70)	We suggest that the term “New” be removed from the heading for the Boiler #13 conditions.	Removed
XXV.E.3.b (page 70)	In this NOx condition for Boiler #13, we suggest that the numerical limit be clarified to indicate it is a NOx limit. Additionally, we suggest that the reference to the CEMs be removed as it is discussed in Section XX.H.	Updated
XXV.E.3.d (page 70)	For clarity, we suggest the CO condition for Boiler #13 be reworded, as follows: “CO emissions from Boiler #13 shall be minimized by utilizing utilize proper design and good combustion practices, and not exceed 8.36 lb/hr following as demonstrated with EPA Federal Reference Method 10.”	Updated

XXV.E.3.e (page 70)	For clarity, we suggest the VOC condition for Boiler #13 be reworded, as follows:“ VOC emissions from Boiler #13 shall be minimized utilize by utilizing proper design and good combustion practices, and shall be demonstrated by compliance with the CO emission limit and completion of the preventative tune-ups required by per 40 CFR 63 Subpart DDDDD.”	Updated
XXV.E.3.f (page 70)	For clarity, we suggest the PM ₁₀ /PM _{2.5} condition for Boiler #13 be reworded, as follows :“CHS Boiler #13 shall utilize proper design and good combustion practices and complete the preventative tune-ups required by 40 CFR 63 Subpart DDDDD to minimize PM10/PM2.5 emissions at Boiler #13 and the preventative tune-ups per 40 CFR 63 Subpart DDDDD.” ”	Updated
XXV.E.3.g.ii (page 70)	For clarity, we suggest adding the word “Completing” to the beginning of this condition.	Updated
XXV.E.4 (page 71)	This condition includes combined tons per rolling 12-calendar month NOx, SO ₂ and CO emission limits for the #2 CU Vacuum Heater (05HT0002), Coker Charge Heater (H-7502) and Boiler #13. For a number of reasons related to this particular project, our preference is that the limits be set on an emissions unit by emissions unit basis rather than being combined. As such, the limits expressed as tons per rolling 12-calendar month totals, would be as follow:#2 CU Vacuum Heater: NOx: 4.59; SO ₂ : 0.84; CO: 4.59 Coker Charge Heater (H-7502): NOx: 28.17, SO ₂ : 5.92; CO: 28.17 Boiler #13: NOx: 27.47, SO ₂ : 6.72; CO: 36.63	Updated as three individual limits
XXV.F.4 (page 71), G.5 (page 72) and H.5 (page 73)	We suggest that these VOC compliance demonstration conditions be expanded to also include the recordkeeping required by 40 CFR 63 Subpart DDDDD.	Updated
XXV.F.5 (page 71)	We suggest this condition be revised for clarity, as follows: “Compliance for the #2 CU Vacuum Heater PM10/PM2.5 condition in Section XXV.E.1.e shall be demonstrated thru documented via the recordkeeping requirements per of 40 CFR 63 Subpart DDDDD.”	Updated
XXV.F.6 (page 71)	For consistency, we suggest this condition be worded similarly to the proposed condition F.5 (above), as follows: “Compliance for the #2 CU Vacuum Heater CO ₂ e condition in Section XXV.E.1.f shall be demonstrated via the recordkeeping requirements of 40 CFR 63 Subpart DDDDD.”	Updated
XXV.G.2 and 3 (page 72)	We suggest these Coker Charge Heater (H-7502) monitoring conditions be updated to indicate the following CEM requirements: G.2: NOx lb/hr limit: NOx CEMs and stack flow monitor required G.3: NOx concentration or lb/MMBtu limit: NOx and O ₂ CEMs required	Updated
XXV.G.6 (page 72)	We suggest this condition be revised for clarity, as follows: “Compliance for the Coker Charge Heater PM10/PM2.5 condition in Section XXV.E.2.f shall be thru documented demonstrated via the recordkeeping requirements per of 40 CFR 63 Subpart DDDDD.”	Updated
XXV.G.7 (page 72)	For consistency, we suggest this condition be worded similarly to the proposed condition G.6 (above), as follows: “Compliance for the Coker Charge Heater CO ₂ e condition in Section XXV.E.2.g shall be demonstrated via the recordkeeping requirements of 40 CFR 63 Subpart DDDDD.”	Updated

XXV.H.2 and 3 (page 72)	We suggest these Boiler #13 monitoring conditions be updated to indicate the following CEM requirements: H.2: NOx lb/hr limit: NOx CEMs and stack flow monitor required H.3: NOx lb/MMBtu limit: NOx and O2 CEMs required	Updated
XXV.H.6 (page 73)	We suggest this condition be revised for clarity, as follows: “Compliance for the Boiler #13 PM10/PM2.5 condition in Section XXV.E.3.f shall be demonstrated via the recordkeeping requirements per of 40 CFR 63 Subpart DDDDD.”	Updated
XXV.H.7 (page 73)	For consistency, we suggest this condition be worded similarly to the proposed condition H.6 (above), as follows: “Compliance for the Boiler #13 CO2e condition in Section XXV.E.3.g shall be demonstrated via the recordkeeping requirements of 40 CFR 63 Subpart DDDDD.”	Updated
PA I.D (page 50)	In this Process Description section of the permit analysis, there is a list that summarizes the emitting units associated with the MUE. We suggest that it be noted that the #2 CU Vacuum Heater (005HT0002) is a new, replacement heater for the existing #2 CU Vacuum Heater (2CV-HTR-2) and that Boiler #9 will be permanently shut down.	Updated
PA – III (page 75)	There is an extra parenthesis in the first sentence under the “Step 2” section.	Removed
PA – III (page 82)	In the third paragraph of the “Steps 4 and 5: Evaluation of Most Effective PM Control Technologies/BACT Selection”, we offer the following edits to the final two sentences for clarification: “Although, the RBLC has identified the emission factor of 0.0075 lb/MMBtu for use in calculating emission rates, the demonstration for these hourly emission rates will be at the request of the Department because heater sizes are not significantly large and CHS will utilizing utilize clean burning fuels and complete 40 CFR 63 Subpart DDDDD tune-ups that will result in leading to provide low annual emission rates. Additionally, the RBLC database indicates that many of the PM10/PM2.5 limits within the database do not provide a compliance determination method determination .”	Updated
PA – III (page 85)	In the “Step 5: Process Heater and Boiler BACT for CO2e” discussion, we suggest that a sentence or two be added to note that rather than numeric limits, completion of the 40 CFR 63 Subpart DDDDD tune-ups will be used to minimize CO2e emissions from the new sources.	Updated
PA – III (page 90)	In the first sentence of the Equipment Leaks VOC BACT paragraph, we suggest the word “feedstocks” be replaced with “products”.	Updated
PA – III (page 94)	The following comments are provided to add clarity to the third paragraph of the “NOx Limit Review for Boilers #11 and #12.” · 1st sentence: Boilers 11 and 12 began operation in 2007 and 2009, respectively. · 7th sentence: “...methane which is the primary component fuel in the RFG.” · 8th sentence: We suggest changing the word “inability” to “challenge”. · 12th sentence: “The RFG hydrogen composition concentration and variability was not well known....”	Updated
PA – III (page 94)	The following comments are provided to add clarity to the fourth paragraph of the “NOx Limit Review for Boilers #11 and #12”. 4th sentence: “...particularly given the boilers, at the time of this permit action, are now twelve eleven to thirteen years old.” · 5th sentence: “...would provide for total potential emissions of 27.48 tpy...”	Updated

PA – VI (page 97)	In the second to last sentence on this page, we suggest the following update: “For this project, NO2 1-hour Class II SILs were exceeded, which required a NAAQS analysis.”	Updated
PA – VI (page 100)	In the third paragraph on this page, we suggest “rations” be updated to “ratios”.	Updated
PA – VI (page 100)	In “Table VI-3 Onsite Source Descriptions”, the source category for the third source listed, 2CVHTR2, should be shown as a “Shutdown Source” rather than an “Other Existing Source”. This heater is being permanently shut down and replaced with a new heater show as “5HT0002” in the table.	Updated
Environmental Assessment (EA) – 2 (page 1)	For clarification, we suggest the following update to the second to last sentence of item 2.: “Previous limits were established by vendor guarantees and have since been determined to be unachievable since start-up during certain desired operating scenarios.”	Updated
XI.H.2	Outdated compliance reporting for drum pressure	Removed

G. Additional Information

Additional information, such as applicable rules and regulations, Best Available Control Technology (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.
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 Montana Clean Air Act, 75-2-101, *et seq.*, MCA.

CHS 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.

4. ARM 17.8.110 Malfunctions. The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation, or to continue for a period greater than 4 hours.
5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction of the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

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

1. ARM 17.8.204 Ambient Air Monitoring
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
7. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
8. ARM 17.8.221 Ambient Air Quality Standard for Visibility
9. ARM 17.8.222 Ambient Air Quality Standard for Lead
10. ARM 17.8.223 Ambient Air Quality Standard for PM₁₀

CHS must comply with the applicable ambient air quality standards.

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

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.
2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, CHS 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. Commencing July 1, 1971, no person shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions.
6. ARM 17.8.324 Hydrocarbon Emissions – Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.
7. ARM 17.8.340 Standard of Performance for New Stationary Sources. 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, Standards of Performance for New Stationary Sources (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 Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.
 - c. Subpart J – Standards of Performance for Petroleum Refineries.
 - d. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (The new gasoline/distillate truck loading rack VCU is subject only to the H₂S in fuel gas or SO₂ emission limit).
 - e. Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.
 - f. Subpart XX – Standards of Performance for Bulk Gasoline Terminals the construction or modification of which is commenced after December 17, 1980.
 - g. Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture.
 - h. Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or before November 7, 2006.

- i. Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.
 - j. Subpart QQQ – Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems.
- 8. ARM 17.8.341 Emission Standards for Hazardous Air Pollutants. This source shall comply with the standards and provisions of 40 CFR Part 61, as appropriate.
 - a. Subpart A – General Provisions apply to all equipment or facilities subject to a Subpart as listed below.
 - b. Subpart FF – National Emissions Standards for Benzene Waste Operations.
- 9. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR Part 63, shall comply with the requirements of 40 CFR Part 63, as listed below:
 - a. Subpart A – General Provisions applies to all NESHAP source categories subject to a Subpart as listed below.
 - b. Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.
 - c. Subpart UUU – MACT Standard for Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.
 - d. Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.
 - e. Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters.
- D. ARM 17.8, Subchapter 4 – Stack Height and Dispersion Techniques, including, but not limited to:
 - 1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.
 - 2. ARM 17.8.402 Requirements. CHS must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP).

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

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. CHS submitted the appropriate permit application fee for the current permit action.
2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

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

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

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.
2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify, or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. CHS has a PTE greater than 25 tons per year of SO₂, NO_x, CO, VOC, and PM emissions; therefore, an air quality permit is required.
3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.
4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under Montana Air Quality Permit Program.
5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, modification, or use of a source. CHS 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. CHS submitted an affidavit of publication of public notice for the March 6, 2020, issue of the *Billings Gazette*, a newspaper of general circulation in the City of Billings in Yellowstone 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 CHS 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 Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.

CHS's existing petroleum refinery in Laurel is defined as a "major stationary source" because it is a listed source with a PTE more than 100 tons per year of several pollutants (PM, SO₂, NO_x, CO, and VOCs).

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

ARM 17.8.904 When Air Quality Preconstruction Permit Required. This rule requires that major stationary sources or major modifications located within a nonattainment area must obtain a preconstruction permit in accordance with the requirements of this Subchapter, as well as the requirements of Subchapter 7. MAQP #1821-41 does not trigger Subchapter 9.

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 tons/year of any pollutant;
 - b. PTE > 10 tons/year of any one HAP, PTE > 25 tons/year of a

combination of all HAPs, or a lesser quantity as the Department may establish by rule; or

c. PTE > 70 tons/year of PM₁₀ in a serious PM₁₀ nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program Applicability. (1) Title V of the FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204 (1), obtain a Title V Operating Permit. In reviewing and issuing MAQP #1821-43 for CHS, the following conclusions were made:

a. The facility's PTE is greater than 100 tons/year for several pollutants.

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

c. This source is not located in a serious PM₁₀ nonattainment area.

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

e. This facility is subject to current NESHAP (40 CFR 61 Subpart FF and 40 CFR 63 Subparts CC, UUU, ZZZZ, and DDDDD).

f. This source is neither a Title IV affected source, nor a solid waste combustion unit.

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

Based on these facts, the Department determined that CHS is a major source of emissions as defined under Title V. CHS is currently in the process of updating their Title V operating permit with a renewal application being reviewed by the Department.

J. MCA 75-2-103, Definitions, provides, in part, as follows:

1. "Incinerator" means any single or multiple-chambered combustion device that burns combustible material, alone or with a supplemental fuel or catalytic combustion assistance, primarily for the purpose of removal, destruction, disposal, or volume reduction of all or any portion of the input material.

2. "Solid waste" means all putrescible and nonputrescible solid, semisolid, liquid, or gaseous wastes, including, but not limited to...air pollution control facilities.

K. MCA 75-2-215, Solid or Hazardous Waste Incineration -- Additional Permit Requirements, including, but not limited to, the following requirements:

The Department may not issue a permit to a facility until the Department has reached a determination that the projected emissions and ambient concentrations will constitute a negligible risk to the public health, safety, and welfare and to the environment.

Health Risk Assessment (MAQP #1821-04)

For MAQP #1821-04, CHS submitted a health risk assessment identifying the risk from the burning of HAPs in the flare as part of their permit application. The risk assessment contained the HAPs from the 1990 Federal Clean Air Act Amendments with an established risk value. The ambient concentrations were determined using ISCT3 and the risk assessment model used EPA's unit risk estimates and reference concentrations. The Department included limits in the permit that ensure the amount of material used in the models was not exceeded. The risk assessment results were summarized in the following table.

Flare Risk Assessment - CHS Refinery, MAQP #1821-04

Chemical Compound	Hourly Conc $\mu\text{g}/\text{m}^3$	Cancer ELCR Chronic	Non-Cancer Hazard Quotient Chronic Acute	
Benzene*	4.67E-02	8.3E-06	3.9E-07	ND
Toluene	3.82E-02	ND	ND	ND
Ethyl Benzene	2.85E-03	ND	ND	ND
Xylenes	1.25E-02	ND	ND	ND
Hexane	8.55E-02	ND	ND	ND
Cumene	1.14E-04	ND	ND	ND
Naphthalene	1.60E-05	ND	ND	ND
Biphenyl	7.98E-08	ND	ND	ND
Total Risks =	0.186	8.3E-06	3.9E-07	ND

*The reference concentration for Benzene is $71 \mu\text{g}/\text{m}^3$ (EPA IRIS database).

The modeling demonstrated that the ambient concentrations of HAPs, with the exception of Benzene, are less than the concentrations contained in Table I and Table II of ARM 17.8.770; therefore, these HAPs were excluded from further review.

A risk assessment for Benzene was calculated because the predicted ambient concentration was greater than the concentration contained in Table I of ARM 17.8.770. This assessment demonstrated that the excess lifetime cancer risk was 3.9×10^{-7} . Therefore, the Department determined that the health risk assessment model demonstrated negligible risk to public health in this case.

Health Risk Assessment (MAQP #1821-13)

For MAQP #1821-13, CHS submitted a health risk assessment identifying the risk from the burning of HAPs in the rail loading rack VCU as part of their permit application. The risk assessment contained the HAPs from the 1990 Federal Clean Air Act Amendments with an established risk value. The ambient concentrations were determined using ISC3 and the risk assessment model used EPA's unit risk estimates and reference concentrations. The Department included limits in the permit that ensure the amount of material used in the models was not exceeded. The risk assessment results were summarized in the following table.

Rail Loading Rack VCU Risk Assessment - CHS Refinery, MAQP #1821-13

Modeled Table 1* Table 2*

Chemical Compound	Conc. µg/m ³	Conc.1 µg/m ³	Conc. µg/m ³
Benzene	1.81E-02	1.20E-02	7.10E-01
Ethyl Benzene	8.29E-04	--	1.00E+01
Naphthalene	4.08E-05	--	1.40E-01
Toluene	1.22E-02	--	4.00E+00
Xylenes	4.35E-03	--	3.00E+00
Hexane	2.68E-02	--	2.00E+00

Total concentrations = 0.0623

*Refers to ARM 17.8.770

The modeling demonstrated that the ambient concentrations of HAPs, with the exception of Benzene, are less than the concentrations contained in Table 1 and Table 2 of ARM 17.8.770; therefore, these HAPs were excluded from further review.

A risk assessment for Benzene was calculated because the predicted ambient concentration was greater than the concentration contained in Table I of ARM 17.8.770. The modeled benzene concentration was compared to EPA Region III's, "Risk-Based Concentration (RBC) Table," dated October 2005. RBC screening levels represent concentrations which are determined to present a lifetime cancer risk of no greater than 1×10^{-6} . The RBC concentration for benzene is listed as 2.3×10^{-1} , which is higher than the modeled concentration for benzene. Therefore, the Department determined that the health risk assessment model demonstrated negligible risk to public health in this case.

Although CHS proposes to expand the railcar light product loading rack under MAQP #1821-17, no modifications to the VCU are proposed. In addition, the basis for the Human Health Risk assessment submitted as part of MAQP #1821-13 has not changed. As such, an additional assessment is not necessary for the proposed expansion of the railcar light product loading rack.

Also for MAQP #1821-13, CHS submitted a health risk assessment identifying the risk from the burning of HAPs in the coker unit TGI as part of their permit application. The risk assessment contained the HAPs from the 1990 Federal Clean Air Act Amendments with an established risk value. The ambient concentrations were determined using SCREEN3 and the risk assessment model used EPA's unit risk estimates and reference concentrations. The Department included limits in the permit that ensure the amount of material used in the models was not exceeded. The risk assessment results were summarized in the following table.

Coker Unit TGI Risk Assessment - CHS Refinery, MAQP #1821-13

Chemical Compound	Modeled Conc. µg/m ³	Table 1* Conc.1 µg/m ³	Table 2* Conc. µg/m ³
Carbon Disulfide	3.18E-02	--	7.00E-00

Total concentrations = 3.18E-02

*Refers to ARM 17.8.770

The modeling demonstrated that the ambient concentrations of the carbon disulfide (the only HAP expected to be emitted), are less than the concentrations contained in Table 1 and Table 2 of ARM 17.8.770; therefore, the carbon disulfide were excluded

from further review. Updated information provided to the Department on October 24, 2006, revised the modeled concentration of carbon disulfide to 3.05E-02, which did not affect this determination. Therefore, the Department determined that the health risk assessment model demonstrated negligible risk to public health in this case.

Health Risk Assessment (MAQP #1821-27)

For MAQP #1821-27, a full health risk assessment was completed as a part of the application identifying the risk from the burning of HAPs in the truck loading rack VCU. The risk assessment evaluated the HAPs listed in the 1990 Federal Clean Air Act Amendments with an established risk value. The EPA model AERSCREEN was utilized to estimate a worst case-hourly average concentration of VOCs. To estimate peak concentrations of individual toxic compounds, the maximum VOC concentration was multiplied by speciation factors for gasoline vapors. The Department reviewed the health risk assessment submitted by CHS and verified the results.

ARM 17.8.770(1)(c) exempts individual pollutants from the requirement to perform an HRA provided “exposure from inhalation is the only appropriate pathway to consider” and the ambient concentration of the pollutant is less than the screening levels specified in Table 1 or Table 2 of the rule. Using these tables is considered appropriate because the HAPs emitted from the VCU are not expected to deposit, so inhalation would be the predominant exposure pathway.

The screening threshold tables contain screening-level risk thresholds for chronic cancer risk and chronic and acute non-cancer hazard, though all three values are not provided for all of the HAPs considered in this analysis. Where a screening value was not available, the risk of that type of exposure effect was considered negligible. The results presented in table below show that benzene is the only pollutant for which risk assessments should be performed. All other modeled concentrations are below the screening values.

Loading Rack VCU - Screening Level Concentrations

Annual Average, 0.1 x One Hour Maximum VOCs [$\mu\text{g}/\text{m}^3$] ^(a) = 7.055				
Chemical	Annual Average [$\mu\text{g}/\text{m}^3$]	Cancer Chronic^(b) [$\mu\text{g}/\text{m}^3$]	Non-Cancer Chronic^(c) [$\mu\text{g}/\text{m}^3$]	Non-Cancer Acute^(c) [$\mu\text{g}/\text{m}^3$]
Benzene	6.35E-02	1.20E-02	0.71	N/A
Ethylbenzene	7.10E-03	N/A	10.0	N/A
n-Hexane	1.13E-01	N/A	2.0	N/A
Toluene	9.17E-02	N/A	4.0	N/A
m-Xylene	3.53E-02	N/A	3.0	44.0

(a) Annual Maximum concentration calculated by apply a scaling factor of 0.1, as recommended by MDEQ and EPA’s Screening Procedures for Estimating the Air Quality Impact of Stationary Sources (October 1992, EPA-454/R-92-019)

(b) ARM 17.8.770, Table 1.

(c) ARM 17.8.770, Table 2.

Because the peak annual average modeled concentrations of benzene exceeded the ARM 17.8.770 screening-level concentration thresholds, a more refined risk assessment was performed for inhalation exposure to this HAP. General methodology described in EPA's Human Health Risk Assessment Protocol (HHRAP) was followed.³

The peak annual average modeled concentration of benzene was multiplied by a Unit Risk Factor (URF) published by EPA for this type of analysis.⁴ The result of this calculation conservatively estimates the probability of developing cancer from exposure to a pollutant or a mixture of pollutants over a 70-year lifetime, usually expressed as the number of additional cancer cases in a given number of people. For example, a cancer risk value of 1.0E-06 is interpreted as a one-in-a-million lifetime probability of the exposure resulting in cancer.

The annual average benzene concentration was divided by its respective Reference Concentrations (RfC) to determine individual non-cancer hazard quotients. RfCs have been developed to compare effects of a theoretical exposure to a standard exposure level with known effects. They represent estimates of daily concentrations that, when exposure persists over a given period of time (generally 70 years for chronic effects), adverse effects are considered unlikely. The individual hazard quotients were also summed to derive a cumulative hazard index value. Results of the cancer risk and non-cancer hazard assessments are presented below.

Calculated Risk Summary

Chemical	Annual Average Concentration (µg/m ³)	EPA Risk Factors ^(a)		Calculated Cancer Risk	Calculated Non-Cancer Chronic HQ
		Cancer, Chronic (per µg/m ³)	Non-Cancer Chronic HQ (µg/m ³)		
Benzene	0.0635	7.80E-06	30.0	4.95E-07	2.12E-03
			Total =	4.95E-07	2.12E-03

(a) These chronic dose-response values are available at <http://www.epa.gov/ttn/atw/toxsource/table1.pdf>

ARM 17.8.740(16) defines “negligible risk to the public health, safety, and welfare and to the environment” as “an increase in excess lifetime cancer risk of less than 1.0×10^{-6} , for any individual pollutant, and 1.0×10^{-5} , for the aggregate of all pollutants, and an increase in the sum of the non-cancer hazard quotients [e.g., hazard index] for all pollutants with similar toxic effects of less than 1.0, as determined by a human health risk assessment conducted according to ARM 17.8.767.” As shown, the results of this analysis are all well below these regulatory threshold values.

Increased cancer risk and the non-cancer hazard index were demonstrated to be far below the regulatory thresholds for negligible risk. This demonstration was made with combined worst case or conservative assumptions throughout the modeling and

3 HHRAP chapters are available at <http://www.epa.gov/osw/hazard/tsd/td/comburst/risk.htm#hhrad>. See Chapter 7 for analyses methods.

4 See Table 1 at this EPA web site: <http://www.epa.gov/ttn/atw/toxsource/summary.html>.

risk assessment. These assumptions included:

- Conservative screening level modeling utilizing AERSCREEN
- A person breathing the maximum concentration 24 hours per day, 365 days per year for 70 years

The results of this analysis demonstrate there would be negligible risk to public health from the operation of CHS's product loadout VCU.

Health Risk Assessment (MAQP 1821-33)

In the MAQP #1821-33 permitting action, CHS proposed a Replacement Refinery Flare and a new ammonia combustor associated with the Zone D Sour Water Stripper process. The Replacement Refinery Flare was determined exempt from the requirements of ARM 17.8.770, as the definition of an incinerator provided in MCA was intended to exclude such flares as described in MCA 75-2-103(12)(b)(i). The purpose of a refinery flare is to reduce the impact to human health and the environment from the emissions of process gasses by destruction of those gases through combustion. The Main Refinery Flare serves as an important safety device for refinery operations, and is regulated under 40 CFR 60 Subpart Ja, 40 CFR 60.18, 40 CFR 63.11, and subject to air quality permit review.

The new ammonia combustor is associated with a new two stage sour water stripper. The sour water stripper results in two waste gas streams, one rich in reduced sulfur compounds, and one rich in ammonia. The waste gas stream rich in reduced sulfur compounds will be treated at the existing Sulfur Recovery Units, which have been previously permitted and reviewed at the permitted levels with respect to the Incineration requirements. However, as the ammonia stream will be sent to a new ammonia combustor, this combustion process was determined to require review under ARM 17.8.770.

Due to the high moisture content of the ammonia stream, supplemental natural gas must be used to support the combustion of the stream. The total maximum heat input associated with both the natural gas and ammonia streams combined were utilized to estimate HAP emissions from this process for purposes of review under ARM 17.8.770. HAP emissions were estimated using AP-42 HAP emissions factors for natural gas. As shown in Table 2 below, given the orders of magnitude below screening level concentrations of ARM 17.8.770, this approach was determined acceptable.

Exposure from inhalation was determined as the only appropriate pathway to consider given the pollutants and nature and concentration of emissions expected. AERMOD Modeling was conducted to determine maximum exposure concentrations for the HAP pollutants identified. AERMOD inputs are summarized in Table 1 below.

The results of the maximum exposure levels of HAPs compared to the screening levels of ARM 17.8.770 are summarized in Table 2 below.

TABLE 1		
Model Input	Input Value	Input Value Justification
Source Parameters		
Source Type	Point	The flame is enclosed in the SWS. Modeling the unit as a flare is therefore not appropriate.
Pollutant	Other	
Point Source Type	Default	
Rural/Urban	Rural	The land use of the surrounding area was determined to be less than 50% I1, I2, C1, R2 and R3, based upon the land use typing scheme of Auer. The model was therefore not run in urban mode.
Emission Rate	1.0 lb/hr	A unit emission rate was modeled such that individual pollutant impacts could be easily scaled from the results.
Stack Height	170 feet	Provided by manufacturer.
Stack Inside Diameter	2.0 feet	Provided by manufacturer.
Exit Velocity	75 ft/sec	Provided by manufacturer.
Exit Temperature	400 °F	Provided by manufacturer.
Met Data		
AERMET		Five years (2007-2011) of surface meteorological data from Billings, MT and upper air data from Great Falls, MT were used. The AERMET meteorological processor was used to develop the meteorological data along with EPA's AERSURFACE and AERMINUTE pre-processor programs.
Receptor Options		
Fenceline	50m	Receptors were located along the facility fenceline with a 50m spacing.
Cartesian Grids	100 & 500m	Two Cartesian grids were used. One with 100m spacing that extended from the fence to 1500m from the fence. The second had receptors spaced at 500m and extended from 1500 to 15000m. Additional receptors were spaced at 100m in the high elevations where elevated concentrations were noted.
Flagpole Height	0	Receptor concentrations were predicted at ground level. No flagpole receptors were used.
Terrain		
Terrain Options		The terrain processor AERMAP was used to calculate receptor elevations and hill height scale factors. One third arcsecond National Elevation Data were used to derive these values.

TABLE 2		
Pollutant	Annual SWSI Concentration (µg/m³)	ARM 17.8.770 Screening Concentration (µg/m³)
17.8.770 Table 1 HAPs		
Benzene	2.22E-06	1.20E-02
Formaldehyde	7.94E-05	7.69E-03
Benzo(a)anthracene	1.90E-09	5.88E-05
Benzo(b)fluoranthene	1.90E-09	5.88E-05
Benzo(a)pyrene	1.27E-09	5.88E-05
Dibenz(a,h)anthracene	1.27E-09	5.88E-05
Indeno(1,2,3-cd)pyrene	1.90E-09	5.88E-05
17.8.770 Table 2 HAPs		
Hexane	1.90E-03	2.0
Naphthalene	6.45E-07	0.14
Toluene	3.59E-06	4.0
Arsenic Compounds	2.11E-07	5.00E-03
Beryllium	1.27E-08	4.80E-05
Cadmium Compounds	1.16E-06	3.50E-02
Chromium Compounds	1.48E-06	2.00E-05
Lead Compounds	5.28E-07	1.50E-02
Manganese Compounds	4.01E-07	5.00E-04
Mercury Compounds	2.75E-07	3.00E-03
Nickel Compounds	2.22E-06	2.40E-03
Selenium Compounds	2.54E-08	5.00E-03

Table 2 above demonstrates all pollutant levels were determined to be significantly below the screening levels of ARM 17.8.770. In accord with ARM 17.8.770, there would be negligible risk to public health from the ammonia combustor emissions. 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, welfare and the environment. The Montana Environmental Policy Act review is attached to MAQP #1821-33, with no significant impacts determined, based on the extremely low level of concentrations expected.

Health Risk Assessment (MAQP 1821-41)

CHS has presented a human health risk assessment regarding the proposed thermal combustor. Destruction efficiencies were assumed to be 98 percent which is considered to be the minimum generally expected for incinerators. ARM 17.8.770(1)(c) exempts individual pollutants from the requirements to perform a human health risk assessment if inhalation is the only exposure pathway and ambient concentrations are below levels in Table 1 or Table 2 of the rule. Inhalation is the only exposure pathway. Results of screening modeling demonstrate that no pollutants are above levels in Table 1 or Table 2 of the rule.

Pollutant	Maximum Annual Impact ^a (µg/m ³)	Maximum 1-hr Impact ^b (µg/m ³)	Table 1 Cancer Screen Level ^c (µg/m ³)	Table 2 Non-cancer Chronic Screen Level ^d (µg/m ³)	Table 2 Non-cancer Acute Screen Level (µg/m ³)	Maximum Impact below Table 1 Cancer Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Chronic Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Acute Screen Level (Yes/No)
1 HYDROXY 2 METHYL BENZENE (o-cresol)	7.71E-06	2.88E-04	-	1.80E+00	-	-	Yes	-
1 HYDROXY 3 METHYLBENZENE (m-cresol)	2.30E-06	8.61E-05	-	-	-	-	-	-
1 HYDROXY 4 METHYLBENZENE (p-cresol)	1.47E-05	5.50E-04	-	-	-	-	-	-
1,1 DICHLOROETHENE vinylidene chloride	1.32E-05	4.95E-04	2.00E-03	3.20E-01	-	Yes	Yes	-
1,2 DICHLOROBENZENE (-o)	4.64E-07	1.73E-05	-	-	-	-	-	-
1,3 DICHLOROBENZENE (-m)	9.55E-07	3.57E-05	-	-	-	-	-	-
1,4 DICHLOROBENZENE (-p)	9.81E-07	3.67E-05	9.09E-03	8.00E+00	-	Yes	Yes	-
DICHLOROBENZENE (mixed isomers)	1.22E-07	4.55E-06	-	-	-	-	-	-
1,2 DICHLOROETHENE trans	4.29E-06	1.60E-04	-	-	-	-	-	-
1,2,4-TRIMETHYLBENZENE	3.60E-04	1.35E-02	-	-	-	-	-	-
1-METHYL NAPHTHALENE	2.04E-04	7.61E-03	-	-	-	-	-	-
2 BUTANONE (methyl ethyl ketone, MEK)	1.94E-06	7.24E-05	-	1.00E+01	-	-	Yes	-
2 METHYLNAPHTHALENE	2.12E-04	7.93E-03	-	-	-	-	-	-
3-METHYLCHLORANTHRENE	1.83E-10	6.83E-09	-	-	-	-	-	-
7,12-DIMETHYLBENZ(A)ANTHRACENE	1.62E-09	6.07E-08	-	-	-	-	-	-
ACENAPHTHENE	1.83E-10	6.83E-09	-	-	-	-	-	-

Pollutant	Maximum Annual Impact ^a (µg/m ³)	Maximum 1-hr Impact ^b (µg/m ³)	Table 1 Cancer Screen Level ^c (µg/m ³)	Table 2 Non-cancer Chronic Screen Level ^d (µg/m ³)	Table 2 Non-cancer Acute Screen Level (µg/m ³)	Maximum Impact below Table 1 Cancer Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Chronic Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Acute Screen Level (Yes/No)
ANTHRACENE	2.44E-10	9.11E-09	-	-	-	-	-	-
ARSENIC	2.03E-08	7.59E-07	2.3256e-05	5.00E-03	-	Yes	Yes	-
BARIUM	4.46E-07	1.67E-05	-	-	-	-	-	-
BENZENE	1.44E-03	5.38E-02	1.20E-02	7.10E-01	-	Yes	Yes	-
BENZO(A)ANTHRACENE	1.83E-10	6.83E-09	5.88E-05	-	-	Yes	-	-
BENZO(A)PYRENE	1.22E-10	4.55E-09	5.88E-05	-	-	Yes	-	-
BENZO(B)FLUORANTHENE	1.83E-10	6.83E-09	5.88E-05	-	-	Yes	-	-
BENZO(G,H,I)PERYLENE	1.22E-10	4.55E-09	-	-	-	-	-	-
BENZO(K)FLUORANTHENE	1.83E-10	6.83E-09	5.88E-05	-	-	Yes	-	-
BERYLLIUM	1.22E-09	4.55E-08	4.17E-05	4.80E-05	-	Yes	Yes	-
BUTANE	2.13E-04	7.97E-03	-	-	-	-	-	-
BUTYL BENZENE	4.01E-05	1.50E-03	-	-	-	-	-	-
CADMIUM	1.12E-07	4.17E-06	5.56E-05	3.50E-02	-	Yes	Yes	-
CHLOROBENZENE	2.11E-06	7.89E-05	-	7.00E-01	-	-	Yes	-
CHLOROFORM	4.48E-06	1.68E-04	4.35E-03	3.50E-01	-	Yes	Yes	-
CHROMIUM	5.68E-09	2.12E-07	8.33E-06	2.00E-05	-	Yes	Yes	-
CHROMIUM VI	5.68E-09	2.12E-07	-	-	-	-	-	-
CHRYSENE	1.22E-06	4.57E-05	-	-	-	-	-	-
COBALT	8.52E-09	3.19E-07	-	-	-	-	-	-
COPPER	8.63E-08	3.23E-06	-	-	-	-	-	-
CUMENE (isopropylbenzene)	1.06E-04	3.97E-03	-	-	-	-	-	-

Pollutant	Maximum Annual Impact ^a (µg/m ³)	Maximum 1-hr Impact ^b (µg/m ³)	Table 1 Cancer Screen Level ^c (µg/m ³)	Table 2 Non-cancer Chronic Screen Level ^d (µg/m ³)	Table 2 Non-cancer Acute Screen Level (µg/m ³)	Maximum Impact below Table 1 Cancer Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Chronic Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Acute Screen Level (Yes/No)
CYCLOHEXANE	9.09E-03	3.40E-01	-	-	-	-	-	-
CYMENE,para	1.72E-05	6.41E-04	-	-	-	-	-	-
DIBENZO(A,H)ANTHRACENE	1.22E-10	4.55E-09	5.88E-05	-	-	Yes	-	-
DICHLOROETHANE(1,1) ethyldenedichloride	2.65E-06	9.90E-05	-	-	-	-	-	-
DICHLOROETHYLENE(1,2) cis	2.59E-06	9.70E-05	-	-	-	-	-	-
ETHANE	3.15E-04	1.18E-02	-	-	-	-	-	-
ETHENYLBENZENE (styrene)	1.01E-06	3.79E-05	-	1.00E+01	-	-	Yes	-
ETHYLBENZENE	3.60E-04	1.35E-02	-	1.00E+01	-	-	Yes	-
FLUORANTHENE	3.04E-10	1.14E-08	-	-	-	-	-	-
FLUORENE	2.84E-10	1.06E-08	-	-	-	-	-	-
FORMALDEHYDE	7.61E-06	2.85E-04	7.69E-03	3.60E-02	3.70	Yes	Yes	Yes
HEXANE(-n)	2.48E-02	9.26E-01	-	2.00E+00	-	-	Yes	-
INDENO(1,2,3-CD)PYRENE	1.83E-10	6.83E-09	5.88E-05	-	-	Yes	-	-
LEAD	5.07E-08	1.90E-06	-	1.50E-02	-	-	Yes	-
MANGANESE	3.86E-08	1.44E-06	-	5.00E-04	-	-	Yes	-
MERCURY	2.64E-08	9.86E-07	-	3.00E-03	0.30	-	Yes	Yes
MOLYBDENUM	1.12E-07	4.17E-06	-	-	-	-	-	-
NAPHTHALENE	4.64E-05	1.74E-03	-	1.40E-01	-	-	Yes	-
NICKEL	2.13E-07	7.97E-06	3.85E-04	2.40E-03	0.01	Yes	Yes	Yes
PENTANE	2.64E-04	9.86E-03	-	-	-	-	-	-
PHENANTHRENE	1.49E-06	5.59E-05	-	-	-	-	-	-

Pollutant	Maximum Annual Impact ^a (µg/m ³)	Maximum 1-hr Impact ^b (µg/m ³)	Table 1 Cancer Screen Level ^c (µg/m ³)	Table 2 Non-cancer Chronic Screen Level ^d (µg/m ³)	Table 2 Non-cancer Acute Screen Level (µg/m ³)	Maximum Impact below Table 1 Cancer Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Chronic Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Acute Screen Level (Yes/No)
PHENOL	8.07E-06	3.02E-04	-	4.50E-01	-	-	Yes	-
PROPANE	1.62E-04	6.07E-03	-	-	-	-	-	-
PROPANONE (acetone)	1.72E-16	6.43E-15	-	-	-	-	-	-
PROPYL(-n) BENZENE	1.28E-04	4.77E-03	-	-	-	-	-	-
PYRENE	5.07E-10	1.90E-08	-	-	-	-	-	-
sec BUTYLBENZENE	2.79E-05	1.05E-03	-	-	-	-	-	-
SELENIUM	2.44E-09	9.11E-08	-	5.00E-03	0.02	-	Yes	Yes
TOLUENE	1.81E-03	6.77E-02	-	4.00E+00	-	-	Yes	-
TRIMETHYLBENZENE (1,3,5)	7.96E-05	2.98E-03	-	-	-	-	-	-
VANADIUM	2.33E-07	8.73E-06	-	-	-	-	-	-
XYLENE	1.55E-03	5.81E-02	-	3.00E+00	44.00	-	Yes	Yes
ZINC	2.94E-06	1.10E-04	-	-	-	-	-	-

CHS also conducted a more refined risk assessment for those HAPs not listed in ARM 17.8.770. Cancer and Non-cancer risks were calculated according to EPA's Human Health Risk Assessment Protocol. Results are shown below.

Pollutant	Maximum Annual Impact ^a (µg/m ³)	Maximum 1-hr Impact ^b (µg/m ³)	Chronic Inhalation Cancer Dose Response Value ^c (µg/m ³) ⁻¹	Calculated Cancer Risk	Chronic Inhalation Non-cancer Dose Response Value (RfC) ^c (mg/m ³)	Acute Inhalation Non-cancer Dose Response Value (RfC) ^c (mg/m ³)	Calculated Non-cancer Risk (HQ)	Calculated Acute Non-cancer Risk (HQ)
1 HYDROXY 2 METHYL BENZENE (o-cresol)	7.71E-06	2.88E-04	-	-	-	110	d	2.62E-09
1 HYDROXY 3 METHYLBENZENE (m-cresol)	2.30E-06	8.61E-05	-	-	-	-	-	-
1 HYDROXY 4 METHYLBENZENE (p-cresol)	1.47E-05	5.50E-04	-	-	-	-	-	-
1,1 DICHLOROETHENE vinylidene chloride	1.32E-05	4.95E-04	-	d	2.00E-01	20	d	2.47E-08
1,2 DICHLOROBENZENE (-o)	4.64E-07	1.73E-05	-	-	-	-	-	-
1,3 DICHLOROBENZENE (-m)	9.55E-07	3.57E-05	-	-	-	-	-	-
1,4 DICHLOROBENZENE (-p)	9.81E-07	3.67E-05	1.10E-05	d	8.00E-01	90	d	4.08E-10
DICHLOROBENZENE (mixed isomers)	1.22E-07	4.55E-06	-	-	-	-	-	-
1,2 DICHLOROETHENE trans	4.29E-06	1.60E-04	-	-	-	-	-	-
1,2,4-TRIMETHYLBENZENE	3.60E-04	1.35E-02	-	-	-	-	-	-
1-METHYL NAPHTHALENE	2.04E-04	7.61E-03	-	-	-	6	-	1.27E-06
2 BUTANONE (methyl ethyl ketone, MEK)	1.94E-06	7.24E-05	-	-	-	-	d	-
2 METHYLNAPHTHALENE	2.12E-04	7.93E-03	-	-	-	6	-	1.32E-06
3-METHYLCHLORANTHRENE	1.83E-10	6.83E-09	6.30E-03	1.15E-12	-	0.2	-	3.41E-11
7,12-DIMETHYLBENZ(A)ANTHRACENE	1.62E-09	6.07E-08	7.10E-02	1.15E-10	-	-	-	-
ACENAPHTHENE	1.83E-10	6.83E-09	-	-	-	0.4	-	1.71E-11
ANTHRACENE	2.44E-10	9.11E-09	-	-	-	-	-	-
ARSENIC	2.03E-08	7.59E-07	4.30E-03	d	1.50E-05	0.0002	d	3.79E-06
BARIUM	4.46E-07	1.67E-05	-	-	-	-	-	-

Pollutant	Maximum Annual Impact ^a (µg/m ³)	Maximum 1-hr Impact ^b (µg/m ³)	Chronic Inhalation Cancer Dose Response Value ^c (µg/m ³) ⁻¹	Calculated Cancer Risk	Chronic Inhalation Non-cancer Dose Response Value (RfC) ^c (mg/m ³)	Acute Inhalation Non-cancer Dose Response Value (RfC) ^c (mg/m ³)	Calculated Non-cancer Risk (HQ)	Calculated Acute Non-cancer Risk (HQ)
BENZENE	1.44E-03	5.38E-02	7.80E-06	d	3.00E-02	1.3	d	4.14E-05
BENZO(A)ANTHRACENE	1.83E-10	6.83E-09	1.10E-04	d	-	0.1	-	6.83E-11
BENZO(A)PYRENE	1.22E-10	4.55E-09	1.10E-03	d	-	0.2	-	2.28E-11
BENZO(B)FLUORANTHENE	1.83E-10	6.83E-09	1.10E-04	d	-	0.2	-	3.41E-11
BENZO(G,H,I)PERYLENE	1.22E-10	4.55E-09	-	-	-	10	-	4.55E-13
BENZO(K)FLUORANTHENE	1.83E-10	6.83E-09	1.10E-04	d	-	0.2	-	3.41E-11
BERYLLIUM	1.22E-09	4.55E-08	2.40E-03	d	2.00E-05	0.025	d	1.82E-09
BUTANE	2.13E-04	7.97E-03	-	-	-	-	-	-
BUTYL BENZENE	4.01E-05	1.50E-03	-	-	-	-	-	-
CADMIUM	1.12E-07	4.17E-06	1.80E-03	d	1.00E-05	0.9	d	4.64E-09
CHLOROBENZENE	2.11E-06	7.89E-05	-	-	1.00E+00	46	d	1.72E-09
CHLOROFORM	4.48E-06	1.68E-04	-	d	9.80E-02	0.15	d	1.12E-06
CHROMIUM	5.68E-09	2.12E-07	-	d	-	1	d	2.12E-10
CHROMIUM VI	5.68E-09	2.12E-07	1.20E-02	6.82E-11	1.00E-04	1.5	5.68E-08	1.42E-10
CHRYSENE	1.22E-06	4.57E-05	1.10E-05	1.35E-11	-	0.2	-	2.29E-07
COBALT	8.52E-09	3.19E-07	-	-	1.00E-04	2	8.52E-08	1.59E-10
COPPER	8.63E-08	3.23E-06	-	-	-	-	-	-
CUMENE (isopropylbenzene)	1.06E-04	3.97E-03	-	-	4.00E-01	250	2.65E-07	1.59E-08
CYCLOHEXANE	9.09E-03	3.40E-01	-	-	-	-	-	-
CYMENE,para	1.72E-05	6.41E-04	-	-	-	-	-	-
DIBENZO(A,H)ANTHRACENE	1.22E-10	4.55E-09	1.20E-03	d	-	10	-	4.55E-13
DICHLOROETHANE(1,1) ethylenedichloride	2.65E-06	9.90E-05	1.60E-06	4.24E-12	5.00E-01	1200	5.29E-09	8.25E-11

Pollutant	Maximum Annual Impact ^a (µg/m ³)	Maximum 1-hr Impact ^b (µg/m ³)	Chronic Inhalation Cancer Dose Response Value ^c (µg/m ³) ⁻¹	Calculated Cancer Risk	Chronic Inhalation Non-cancer Dose Response Value (RfC) ^c (mg/m ³)	Acute Inhalation Non-cancer Dose Response Value (RfC) ^c (mg/m ³)	Calculated Non-cancer Risk (HQ)	Calculated Acute Non-cancer Risk (HQ)
DICHLOROETHYLENE(1,2) cis	2.59E-06	9.70E-05	-	-	-	-	-	-
ETHANE	3.15E-04	1.18E-02	-	-	-	-	-	-
ETHENYLBENZENE (styrene)	1.01E-06	3.79E-05	-	-	1.00E+00	21	d	1.80E-09
ETHYLBENZENE	3.60E-04	1.35E-02	2.50E-06	9.01E-10	1.00E+00	140	d	9.62E-08
FLUORANTHENE	3.04E-10	1.14E-08	-	-	-	0.005	-	2.28E-09
FLUORENE	2.84E-10	1.06E-08	-	-	-	7.5	-	1.42E-12
FORMALDEHYDE	7.61E-06	2.85E-04	1.30E-05	d	9.80E-03	0.055	d	d
HEXANE(-n)	2.48E-02	9.26E-01	-	-	7.00E-01	390	d	2.37E-06
INDENO(1,2,3-CD)PYRENE	1.83E-10	6.83E-09	1.10E-04	d	-	0.15	-	4.55E-11
LEAD	5.07E-08	1.90E-06	-	-	1.50E-04	10	d	1.90E-10
MANGANESE	3.86E-08	1.44E-06	-	-	3.00E-04	50	d	2.88E-11
MERCURY	2.64E-08	9.86E-07	-	-	3.00E-04	0.0006	d	d
MOLYBDENUM	1.12E-07	4.17E-06	-	-	-	-	-	-
NAPHTHALENE	4.64E-05	1.74E-03	3.40E-05	1.58E-09	3.00E-03	130	d	1.34E-08
NICKEL	2.13E-07	7.97E-06	-	d	9.00E-05	1	d	d
PENTANE	2.64E-04	9.86E-03	-	-	-	-	-	-
PHENANTHRENE	1.49E-06	5.59E-05	-	-	-	0.4	-	1.40E-07
PHENOL	8.07E-06	3.02E-04	-	-	2.00E-01	5.8	d	5.21E-08
PROPANE	1.62E-04	6.07E-03	-	-	-	-	-	-
PROPANONE (acetone)	1.72E-16	6.43E-15	-	-	-	-	-	-
PROPYL(-n) BENZENE	1.28E-04	4.77E-03	-	-	-	-	-	-
PYRENE	5.07E-10	1.90E-08	-	-	-	15	-	1.26E-12

Pollutant	Maximum Annual Impact ^a (µg/m ³)	Maximum 1-hr Impact ^b (µg/m ³)	Chronic Inhalation Cancer Dose Response Value ^c (µg/m ³) ⁻¹	Calculated Cancer Risk	Chronic Inhalation Non-cancer Dose Response Value (RfC) ^c (mg/m ³)	Acute Inhalation Non-cancer Dose Response Value (RfC) ^c (mg/m ³)	Calculated Non-cancer Risk (HQ)	Calculated Acute Non-cancer Risk (HQ)
sec BUTYLBENZENE	2.79E-05	1.05E-03	-	-	-	-	-	-
SELENIUM	2.44E-09	9.11E-08	-	-	2.00E-02	0.1	d	d
TOLUENE	1.81E-03	6.77E-02	-	-	5.00E+00	37	d	1.83E-06
TRIMETHYLBENZENE (1,3,5)	7.96E-05	2.98E-03	-	-	-	-	-	-
VANADIUM	2.33E-07	8.73E-06	-	-	-	-	-	-
XYLENE	1.55E-03	5.81E-02	-	-	1.00E-01	22	d	d
ZINC	2.94E-06	1.10E-04	-	-	-	-	-	-
Total Chronic Risk				3.02E-08			1.70E-05	
^a Maximum annual impact modeled at 1 lb/hr scaled by HAP hourly emission rate. ^b Maximum hourly impact modeled at 1 lb/hr scaled by HAP hourly emission rate. ^c Dose-response values are available at https://www.epa.gov/fera/dose-response-assessment-assessing-health-risks-associated-exposure-hazardous-air-pollutants . ^d HAP screened out of evaluation - Denotes no available risk factor								

ARM 17.8.740(16) defines “negligible risk to the public health, safety, and welfare and to the environment” as “an increase in excess lifetime cancer risk of less than 1.0×10^{-6} , for any individual pollutant, and 1.0×10^{-5} , for the aggregate of all pollutants, and an increase in the sum of the noncancer hazard quotients [i.e., hazard index] for all pollutants with similar toxic effects of less than 1.0, as determined by a human health risk assessment conducted according to ARM 17.8.767.” As shown, the results of this analysis are below these regulatory threshold values.

III. BACT Determination

A BACT determination is required for each new or modified source. CHS shall install on the new or modified source the maximum air pollution control capability which is technically practicable and economically feasible, except that BACT shall be utilized. The MUE project is subject to PSD BACT requirements for NO_x, PM₁₀, PM_{2.5} and GHGs. Montana ARM 17.8.752 also requires BACT for all new or modified emission sources regardless of PSD applicability. All BACT analyses are included within this section and identified whether they are specifically covered under PSD BACT or BACT as required by ARM 17.8.752. A summary of the BACT analyses provided from the CHS application is included below.

All BACT Analyses presented here are done so using the following hierarchy.

Step 1: Identify all available control technologies with practical potential for application to the emission unit and regulated pollutant under evaluation;

Step 2: Eliminate all technically infeasible control technologies;

Step 3: Rank remaining control technologies by effectiveness and tabulate a control hierarchy;

Step 4: Evaluate most effective controls and document results; and

Step 5: Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

Additionally, cost estimates were developed using the U.S. EPA's Office of Air and Quality Planning and Standards Cost Control Manual, Fifth and Sixth Editions.

BACT for New Gas-Fired Process Heaters and Boilers

This analysis covers the new #2 Crude Unit Vacuum Heater (005HT0002), the new Coker Charge Heater (H-7502), and the new steam generating boiler (Boiler #13).

These three units are each designed to fire both refinery fuel gas (RFG) and natural gas and as a result will generate nitrogen oxides (NO_x), sulfur dioxide (SO₂), particulate matter (PM, PM₁₀, PM_{2.5}, carbon monoxide (CO), volatile organic compounds (VOCs), sulfuric acid mist and greenhouse gases.

NO_x BACT Analysis

Nitrogen oxides are formed as part of the combustion process and are generally classified in accordance with their formation mechanism as either thermal NO_x or fuel NO_x. Thermal NO_x is formed by the thermal dissociation and subsequent reaction of the nitrogen and oxygen in the combustion air at high temperature. The amount of thermal NO_x formation is a function of the combustion unit and burner design, flame temperature, residence time at flame temperature, and fuel/air ratios in the primary combustion zone. The rate of thermal NO_x formation increases exponentially with the flame temperature.

Fuel NO_x is formed by the gas phase oxidation of the nitrogen that is chemically bound in the fuel. Fuel NO_x formation is largely independent on combustion temperature and the

nature of the organic nitrogen compound. Its formation is dependent on fuel nitrogen content and the amount of excess combustion air. RFG and natural gas contain negligible amounts of fuel bound nitrogen. As such, the predominant type of NO_x that is formed in refinery process heaters and boilers is thermal NO_x.

Control of the air/fuel stoichiometry is critical to achieving reductions in thermal NO_x. Thermal NO_x formation also decreases rapidly as the combustion temperature drops below the adiabatic flame temperature for a given stoichiometry. Maximum reduction of thermal NO_x is achieved by simultaneous control of both combustion temperature and air/fuel stoichiometry.

Step 1: Identification of Available NO_x Control Technologies

Summary results from the RBLC database for gas-fired heaters and gas-fired boilers were presented by CHS. Two fundamental categories of NO_x emission controls were demonstrated for gas-fired process heaters: low NO_x burners (LNB) or ultra-low NO_x Burners (ULNB), and post-combustion catalytic control to selectively reduce NO_x emissions (referred to as selective catalytic reduction or SCR). In addition to the two categories listed above, an additional demonstrated control for gas fired boilers was the application of external flue gas recirculation (FGR).

Additional controls that are applied to the control of NO_x from other types of combustion sources include the following: selective noncatalytic reduction (SNCR), nonselective catalytic reduction (NSCR), and EM_xTM. These controls, which are potentially applicable via technology transfer, are also considered.

The NSPS subpart Ja NO_x standard at 40 CFR 60.102a(g)(2) is applicable to the Coker Charge Heater (H-7502). The Subpart Ja NO_x standard not applicable to the #2 Crude Unit Vacuum Heater (005HT0002) because its design heat input is not greater than 40 MMBtu/hr. The NSPS subpart Db NO_x standard at 40 CFR 60.44b(a)(1) is applicable to the proposed new boiler (Boiler #13).

Step 2: Technical Feasibility of Available NO_x Control Technologies

The following NO_x controls are considered to be demonstrated on gas-fired refinery process heaters and boilers: LNBs/ULNB, SCR, and external FGR (Boiler #13) only. As a result, these controls are considered further by this analysis in Steps 3 through 5.

The technical feasibility of external FGR (process heater), SNCR, NSCR, and EM_xTM are evaluated further in Step 2 using the previously discussed criteria: applicability, availability, and demonstrated in practice.

External Flue Gas Recirculation (FGR): FGR reduces thermal NO_x generation by reducing the concentration of oxygen in the burner flame region, and by providing more mass in the burner zone reducing overall combustion temperatures. There are two forms of FGR: external and internal. The NO_x control mechanism and the effect of FGR on performance for both forms, internal and external, are identical. The only difference between internal and external FGR is in the mechanics of introducing flue gas into the flame zone.

External FGR takes flue gases after heat recovery has been accomplished and recirculates a portion of the flue gas back to the burner combustion zone. To accomplish this, an external

fan and ductwork is required to move the flue gas into the combustion zone. External FGR is primarily used for gas-fired boilers. Unlike petroleum refinery process heaters, gas fired boilers less than 500 MMBtu/hr heat input have few burners (one to four) that are co-located, and coupling the externally recirculated flue gas with the limited number of co-located burners is not difficult. The use of external FGR is considered technically feasible for the proposed boiler and not technically feasible for the proposed process heaters because of the inherent design of the heaters (i.e., 6 burners on #2 CU Vacuum Heater (005HT0002) and 84 burners on Coker Charge Heater (H-7502)).

Internal FGR is accomplished by recirculating the flue gases coming off the burner flame back into the base of the burner flame. Internal FGR is accomplished by the burner design. Burners using internal FGR are referred to as ultra LNB (ULNB). To better control the process tube skin temperatures and prevent coking of the process hydrocarbons in the tubes petroleum refinery process heaters have many small burners. As noted above, the use of ULNB is considered technically feasible for the proposed process heaters and boiler.

Selective Noncatalytic Reduction (SNCR): SNCR is a post-combustion NO_x control technology in which a selective reagent, either ammonia or urea, is injected into the exhaust gases to react with NO_x/NO₂, forming elemental nitrogen and water without the use of a catalyst. This process is effective in reducing NO_x/NO₂ emissions within specific constraints, requiring uniform mixing of the reagent into the flue gas within a zone of the exhaust path where the flue gas temperature is within a narrow temperature range of approximately 1600 to 2000°F. To achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window must be at least one half second. The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range the reagent will convert to NO_x/NO₂ and below the lower end of the temperature range the desired chemical reactions will not proceed and the injected reagent will be emitted as ammonia slip.

Because SNCR's ability to achieve NO_x reduction requires operation of the combustion source within specific ranges it has previously only been applied to the control of NO_x emissions from sources that operate within well-defined operating ranges and that do not rapidly vary across those ranges. Refinery process heaters and boilers operate across much wider ranges. SNCR has not been widely applied within the refinery industry and is not considered feasible for the proposed heaters and boiler. As a result, SNCR is eliminated from further consideration.

Nonselective Catalytic Reduction (NSCR). NSCR is used to reduce NO_x emissions in the exhaust of automotive engines and stationary internal combustion engines. NSCR systems are comprised of three different catalyst types used in series. The first catalyst in the series is a reducing catalyst that is used to react unburned hydrocarbon in the exhaust with NO_x in the exhaust. Tuning the engine to run fuel rich creates the unburned hydrocarbon. The next catalyst in the series is an oxidizing catalyst that is used to oxidize the unburned fuel to CO and water and the final catalyst, which is also an oxidizing catalyst is used to oxidize any remaining CO. NSCR has only been applied to engines because it is impractical to tune a fired combustion source such as a process heater or boiler to combust in a fuel rich manner. As a result, this control type is considered to be infeasible for the proposed application and removed from further review.

EMx™: The EMx™ system (formerly referred to as SCONOX™) is an add-on control device that simultaneously oxidizes CO to CO₂, VOCs to CO₂ and water, NO to NO₂ and

then adsorbs the NO₂ onto the surface of a potassium carbonate coated catalyst. The EMx™ system does not require injection of a reactant, such as ammonia, as required by SCR and SNCR and operates most effectively at temperatures ranging from 300°F to 700°F. The overall chemical reaction between NO₂ and the potassium carbonate catalyst is as follows:



The catalyst has a finite capacity to react with NO₂. As a result, to maintain the required NO_x/NO₂ removal rate, the catalyst must be periodically regenerated. Regeneration is accomplished by passing a reducing gas containing a dilute concentration of hydrogen across the surface of the catalyst in the absence of oxygen. Hydrogen in the regeneration gas reacts with the nitrites and nitrates adsorbed on the catalyst surface to form water and molecular nitrogen. Carbon dioxide in the regeneration gas reacts with the potassium nitrite and nitrates to form potassium carbonate, the original form of the chemical in the catalyst coating. The overall chemical reaction during regeneration is as follows:



The regeneration gas is produced in a gas generator using a two-stage process to produce molecular hydrogen and carbon dioxide. In the first stage, natural gas and air are reacted across a partial oxidation catalyst to form carbon monoxide and hydrogen. Steam is added to the mixture and then passed across a low temperature shift catalyst, forming carbon dioxide and more hydrogen. The regeneration gas mixture is diluted to less than four percent hydrogen using steam. To accomplish the periodic regeneration, the EMx™ system is constructed in numerous modules which operate in parallel so that one module can be isolated and regenerated while the remaining modules are lined up for treatment of the exhaust gas stream.

There are currently six EMx™ units in commercial installations worldwide. All are on natural gas-fired combustion turbines of 45 MW or less. There are no known installations on process heaters or boilers. There are a number of differences between the operation and flue gas characteristics of combustion turbines and the proposed new process heaters and boiler. Specifically, combustion turbines are essentially constant flue gas flow combustion devices no matter what the load. Process heater and boiler gas flow rates are directly proportional to load. The impact on the load following ability of the EMx™ is unknown with respect to process heaters and boilers. Additionally, the concentration of NO_x/NO₂ in the flue gases from process heaters and boilers is much higher than that of the combustion turbine flue gases. This is due to the high oxygen content of the combustion turbine flue gas (~15% O₂) relative to the process heaters and boilers flue gas (~3% O₂). The impact of the flue gas oxygen content and NO_x/NO₂ concentration on the EMx™ is unknown with respect to cracking furnaces. Finally, the combustion turbines where EMx™ has been demonstrated have all been fired with natural gas. The proposed process heaters and boiler will be RFG fired and as a result the flue gas will contain SO₂, which is known to act as a poison to the EMx™ catalyst. It should be noted that the EMx™ vendor does provide a solution for SO₂ containing exhaust gases but this technology has not been demonstrated. Based on the above factors the use of EMx™ to control NO_x emissions from the proposed

process heaters and boiler is considered technically infeasible and this technology is eliminated from further consideration.

Step 3: Ranking of Technically Feasible NO_x Control Technologies

Based on the precedents presented from the RBLC and the discussion above, the following control technologies are considered technically feasible for the control of NO_x from the proposed process heaters and boiler:

LNB/ULNB,
LNB/ULNB with external FGR (Boiler #13 only), and
LNB/ULNB followed by SCR technology.

RBLC limits for NO_x emission using ULNBs range from 0.025 to 0.04 lb/MMBtu for petroleum refinery process heaters and from 0.03 to 0.04 lb/MMBtu for petroleum refinery gas fired boilers. It is not known whether the boiler precedents include external FGR in addition to ULNB. There are a number of factors that influence the NO_x emissions rate that is achievable at a particular process heater or boiler, as follows:

- The specific process application influences the design of the heater and may limit the style of burners that may be used in the application;
- Because heaters and boilers are tuned for a given fuel composition, refineries that have fuel gas compositions that vary significantly in their heat and/or hydrogen content are not able to operate stably or consistently at reduced NO_x levels; and
- Process heaters and boilers that are expected to operate in a wide operating range experience higher NO_x rates on both a lb/MMBtu and lb/hr basis when operating at reduced loads below the effective range of ULNB technology.

For the application of LNB/ULNB plus SCR to process heaters, results show NO_x emission limits ranging from 0.01 to 0.015 lb/MMBtu. For the application of LNB/ULNB plus SCR to RFG boilers, results show NO_x emission limits ranging from 0.015 to 0.02 lb/MMBtu.

The NO_x BACT impacts for the proposed process heaters and boiler are addressed in the following subsection for the application of SCR.

Step 4: Evaluation of Most Effective NO_x Control Technologies

This subsection documents the energy, environmental, and economic impacts associated with applying SCR to the proposed process heaters and boiler. The costs presented were developed in accordance with USEPA's Air Pollution Control Cost Manual methodology for SCR. Capital costs were escalated to 2018 dollars using the Chemical Engineering Plant Cost Index. Costs and emission estimates are based on an SCR inlet NO_x emission rate of 0.04 lb/MMBtu for the process heaters (application of ULNB) and 0.03 lb/MMBtu for the boiler (application of ULNB with FGR), an SCR NO_x emission rate of 0.01 lb/MMBtu (based on RBLC precedents), and full load operation for 8,760 hours per year.

Economic Impacts

The capital costs associated with the installation of SCR systems on the proposed heaters

and boiler are dependent upon the rated heat input of the heater or boiler and range from \$3.8 to \$4.4 million per unit. The capital cost of the SCR system includes the catalyst; catalyst housing, induced draft fan, ammonia storage system; and ammonia injection system.

The annual operating and maintenance (O&M) costs associated with the SCR systems are also heater or boiler size dependent and range from \$155,000 to \$176,000 per year per heater or boiler. The annual O&M costs include the cost of ammonia, catalyst replacement, operating personnel and maintenance. A catalyst life of three years is assumed. The total annual costs of the SCR system range from \$529,800 to \$611,800 per year per heater or boiler. The total annual costs include capital recovery, and O&M costs. The resulting cost effectiveness of the SCR systems applied to the proposed process heaters and boiler ranges from \$29,000 to \$153,900 per ton of NO_x removed.

Environmental Impacts

The application of SCR to the proposed process heaters and boiler will result in the emissions of ammonia and additional fine particulate matter in the form of ammonium salts. The emission of ammonia results from incomplete utilization of all of the ammonia injected before the SCR catalyst. This unreacted ammonia, referred to as ammonia slip, either is exhausted to the atmosphere as ammonia or combines with sulfur species in the flue gas to form ammonium salts.

The installation of an SCR system increases the pressure drop through the heater/boiler flue gas path requiring the installation of an induced draft fan. The induced draft fan electric power requirement and SCR system power requirements result in an increase in the emission rate of criteria pollutants (NO_x, CO, GHGs, etc.) where the power is generated

The spent catalyst is comprised of metals that are not considered toxic. This allows the catalyst to be handled and disposed of following normal waste procedures.

Energy Impacts:

The energy impact of applying SCR to the proposed process heaters and boiler comes from the power required to drive the induced draft fan and operate the ammonia injection and storage equipment.

NO_x BACT Selection

For the conventional petroleum refinery process heaters, the use of ULNB technology is selected as BACT. Based on the adverse economic impacts, ULNB plus SCR was not selected as BACT. The cost effectiveness of applying SCR technology to the BACT applicable process heaters ranges from \$29,000 to \$153,900 per ton of NO_x reduced. These

costs are well above the range of cost effectiveness values considered to be reasonable and acceptable in BACT determinations for control of NO_x emissions.

The following NO_x BACT limits are proposed:

#2 Crude Unit Vacuum Heater 005HT0002:

- 1.05 lb/hour,
- USEPA reference method 7E will be used to demonstrate compliance with the proposed limit.

Coker Charge Heater H-7502:

- 6.43 lb/hour (365-day roll) including periods of startup and shutdown.
- A NO_x continuous emissions monitoring system (CEMS) operated in compliance with 40 CFR 60.107a(C) will be used to demonstrate compliance with the proposed limits.
- Compliance with the lb/hour limits shall be determined using the measured pollutant concentration and stack flow rate determined from a stack flow rate monitor.

For the gas-fired boiler (Boiler #13) the use of ULNB technology with external FGR is selected as BACT. Based on the adverse economic impacts, ULNB plus SCR was not selected as BACT. The cost effectiveness of applying SCR technology to the BACT applicable boiler is \$30,700 per ton of NO_x reduced. This cost is well above the range of cost effectiveness values considered to be reasonable and acceptable in BACT determinations for control of NO_x emissions.

The following emissions limits are proposed:

Boiler 13:

- 6.27 lb/hour, (365-day roll) including periods of startup and shutdown.
- A NO_x continuous emissions monitoring system (CEMS) operated in compliance with 40 CFR 60.48b(b) will be used to demonstrate compliance with the proposed limits.
- Compliance with the lb/hour limits shall be determined using the measured pollutant concentration and stack flow rate determined from a stack flow rate monitor.

The proposed BACT limits are based on the following:

- The variable hydrogen and Btu content of the CHS RFG and its resultant impact on stable NO_x emissions control, and
- The wide range of operating loads that the proposed units will be operated at and the inability of ULNB technology to sustain the same NO_x rate at all load levels.

Process Heater and Boiler PM₁₀ and PM_{2.5} BACT Analyses

Emissions of PM₁₀ and PM_{2.5} from gaseous fuel fired heaters and boilers result from inert solids contained in the combustion air, unburned fuel hydrocarbons resulting from incomplete combustion that agglomerate to form particles, and condensable/secondary particulates formed as acid gases (e.g., conversion of sulfur containing compounds in the

fuel to sulfur trioxide). All of the PM emitted from the heater or boiler stack is expected to be less than 2.5 micrometers in aerodynamic particle size diameter, so the identified precedents for PM₁₀ and PM_{2.5} are assumed to be equivalent. As a result, the BACT analysis presented herein focuses on filterable and condensable particulate matter as measured by EPA Methods 5 or 201, and 202.

Step 1: Identification of Available PM₁₀/PM_{2.5} Control Technologies

A summary of the RBLC database precedents was presented for total PM₁₀ emissions (i.e., filterable plus condensable) from conventional refinery fuel gas fired process heaters and gas fired boilers. As shown, good combustion practices (GCP) and the use of clean or gaseous fuels are the only controls identified for PM₁₀/PM_{2.5} from gas fired heaters and boilers. Emission limits for these determinations ranged from 0.0069 to 0.0075 lb/MMBtu with the vast majority being 0.0075 lb/MMBtu .

The only methods used for controlling PM from gas fired heaters and boilers include the use of clean fuel, such as natural gas and RFG, and GCP. Add-on controls, such as ESP's, baghouses, and scrubbers, have never been applied in the broader context on gas fired combustion sources.

Based on the BACT precedent information presented and taking into account technology transfer from other combustion sources, the following PM emissions control technologies were identified as “available”:

- Add-on control technologies including: electrostatic precipitators, baghouses or fabric collectors, and venturi or packed bed scrubbers;
- Use of clean (i.e., low ash) and low sulfur fuels such as natural gas; and
- Combustion controls and practices designed to minimize the production of soot.

Step 2: Technical Feasibility of PM₁₀/PM_{2.5} Control Technologies

As noted above, there are no known applications of add-on controls for PM emissions from heaters and boilers firing gaseous fuel. This is because PM emissions from the subject sources are inherently low because 1) gaseous fuels have no ash content that would contribute to the formation of PM, and 2) the potential for soot formation is very low if GCPs are followed.

Add-on control technologies such as ESP's, baghouses, and scrubbers are considered technically infeasible for controlling PM emissions from the proposed gas fired heaters and boiler. This is because these technologies have design outlet PM emissions that are typically higher than what gas fired heaters and boilers emit, and because the technologies would be ineffective in removing any additional PM because any filterable PM from gaseous fuel combustion is very fine and cannot be effectively captured. The remaining control methods identified, including fuel specifications and good combustion design/practices are considered technically feasible.

Step 3: Ranking of Technically Feasible PM Control Technologies

Technically feasible PM control technologies for the proposed new heaters and boiler are ranked below in descending order of control effectiveness:

- Use of clean (i.e., low ash), low sulfur fuels such as natural gas and RFG; and
- Combustion controls and practices designed to minimize the production of soot.

Steps 4 and 5: Evaluation of Most Effective PM Control Technologies/BACT Selection

The proposed BACT for PM₁₀ and PM_{2.5} emissions from the proposed heaters and boiler includes each of the technically feasible approaches described above. Therefore, no further evaluation of control technologies is necessary.

Based on a PM₁₀/PM_{2.5} emissions rate of 0.0075 lb/MMBtu, CHS proposes the following total PM₁₀/PM_{2.5} BACT limits:

- #2 Crude Unit Vacuum Heater (005HT0002): 0.20 lb/hour
- Coker Charge Heater (H-7502): 1.20 lb/hour
- Boiler #13: 1.56 lb/hr
- Compliance determined using USEPA reference method 5 or 201 and method 202 (i.e., total of filterable and condensable particulates).

These proposals are consistent with the RBLC review findings for conventional refinery fuel gas fired process heaters and gas fired boilers. Although, the RBLC has identified the emission factor of 0.0075 lb/MMBtu for use in calculating emission rates, the demonstration for these hourly emission rates will be at the request of the Department because heater sizes are not significantly large and CHS will utilize clean burning fuels and complete 40 CFR 63 Subpart DDDDD tune-ups that will result in low annual emissions rates. Additionally, the RBLC database indicates that many of the PM₁₀/PM_{2.5} limits within the database do not provide a compliance determination method.

Process Heater and Boiler GHG BACT Analyses

The proposed heaters and boiler will combust natural gas and RFG and will emit three GHG's: CH₄, CO₂, and N₂O. Natural gas and RFG contain carbon, and much of the heat released comes from the oxidation of the carbon in the fuel to form CO₂. Methane from the combustion of natural gas and RFG is a product of incomplete combustion and is emitted in much smaller quantities than CO₂. Trace quantities of N₂O are generated by oxidation of nitrogen in the air used for combustion.

Step 1: Identify Heater and Boiler GHG Control Options

There are three broad strategies for reducing the amount of GHG emissions from combustion sources such as process heaters and boilers: energy efficiency, use of low carbon fuels, and carbon capture and sequestration (CCS). Energy efficiency and the use of low carbon fuels are discussed below.

Energy Efficiency: The use of a highly efficient design and operation of the proposed heaters and boiler to minimize the fuel required to operate will directly impact the amount of CO₂ produced. The strategies used for highly efficient design and operation are process and emissions unit specific but may include:

- Process integration and heat recovery,
- Stack temperature reduction,

- Process fluid or boiler feed water preheating by recovering heat from the combustion flue gases,
- Air preheat recovering heat from the combustion flue gases,
- Condensing economizer recovering heat from the combustion flue gases, and
- Oxygen trim control by monitoring oxygen concentration in the flue gas to maximize thermal efficiency.

The use of the above energy efficiency options will be addressed for the conventional petroleum refinery process heaters and the boiler in the subsequent subsections.

Lower-Emitting Fuel: Typical GHG emissions from combustion of various fossil fuels, including the natural gas and RFG that will be burned by the proposed heaters and boiler. The combustion of natural gas and RFG inherently emits less GHGs than other fossil fuels. This is true because natural gas and RFG have low carbon-to-hydrogen ratios.

Note also that the global warming impact from combusting natural gas and RFG is overwhelmingly from CO₂ emissions; so, the opportunities for minimizing GHG impacts lies primarily in options for controlling or reducing the amount of the CO₂ emissions.

Step 2: Eliminate Technically Infeasible Control Options

Low Carbon Fuel and Feedstocks: As noted above, natural gas and RFG have the lowest CO₂ emission rates of the fossil fuels. Accordingly, the preferential burning of these low-carbon gaseous fuels to meet the process heater or boiler energy needs is considered a CO₂ control technique. This control technique is technically feasible for the proposed heaters and boiler.

Energy Efficiency: For an integrated petroleum refinery, there are several ways to improve energy efficiency. The previously identified options are described below identifying the technical feasibility of each to the proposed process heaters and boiler.

Process Integration and Heat Recovery: Process integration and heat recovery opportunities include directly feeding one process unit from another without going to intermediate storage, optimizing feed-to-product heat exchange, and replacing existing heat exchange equipment with more advanced heat exchange equipment. These options are applicable and technically feasible to the proposed process heaters and will be utilized by CHS to maximize process energy efficiency.

Stack Temperature Reduction: Stack temperature reduction refers to recovering heat from the flue gas after the flue gas leaves the convection tubes of the heater or boiler. Stack temperature reduction from process heaters or boilers results in less heat loss to the atmosphere from combustion exhaust gases. The methods used to recover this heat are discussed below.

Combustion Air Preheat: Air preheat is a method of recovering heat from the hot combustion exhaust gas by heat exchange with the combustion air before it enters the combustion chamber of the heater. Preheating the combustion air reduces the amount of fuel required in a heater because the combustion air does not have to be heated from ambient temperature to the fuel combustion temperature by combusting fuel. This heat recovery approach is commonly used on large process heaters and boilers. To equip a heater or boiler with air preheat requires the addition of a draft fan and heat exchanger, incurring

capital, operating and maintenance costs. For heaters or boilers of sufficient size these costs can be offset by the fuel savings. Although combustion air preheat reduces the amount of CO₂ emitted, NO_x emissions increase because preheating the combustion air increases combustion temperature.

Heating Process Fluids or Boiler Feed Water: Process fluid or boiler feed water preheat is a method of recovering heat from the hot combustion flue gas emitted by heaters/boilers through heat exchange with the boiler feed water or a process fluid. These systems are referred to as economizers when used to preheat water. Preheating the boiler feed water reduces the amount of fuel required in the boiler because the feed water does not have to be heated from ambient temperature to the required steam temperature by combusting fuel.

There are two principal types of economizers: noncondensing and condensing. The new boiler will be equipped with noncondensing economizers to recover heat from the boiler flue gas to heat the boiler feed water. The new process heaters will be natural draft units which makes the inclusion of additional heat transfer surface at the rear of the heater infeasible.

Condensing economizers will not be used due to the special metallurgy required for the economizer and stack, its impact on plume dispersion, and the undemonstrated nature of this technology on conventional petroleum refinery heaters and boilers. As the name implies condensing economizers cool the flue gas down below the moisture and acid gas condensation temperatures. This results in acidic water that is corrosive to carbon steel with which condensing economizers and exhaust stacks are made. As such, the condensing economizer and associated stack must be fabricated of corrosion resistant materials (e.g., stainless steel) significantly increasing cost. Additionally, the condensed moisture must be collected and handled by the wastewater treating system. Cooling the flue gas below the moisture and acid condensation temperature significantly reduces the plume rise of the exhaust gas negatively impacting dispersion of air pollutants and creating emissions of localized acid rain. Condensing economizers have been commercially demonstrated on small gas fired boilers where there is a process use for warm water. CHS is not aware of any condensing economizer applications on conventional petroleum refinery heaters or boilers making the use of condensing economizers a research project.

Oxygen trim control: Excessive amounts of combustion air used in process heaters and boilers results in heat inefficiencies because more fuel combustion is required to heat the unnecessary air to combustion temperatures. This can be alleviated by using state-of-the-art instrumentation for monitoring and controlling the excess air levels in the combustion process. The result is a reduction in the heat input because the amount of combustion air needed for safe and efficient combustion is minimized. This requires the installation of oxygen monitors in the furnace stacks and damper controls on the combustion air dampers. Lowering excess air levels, while maintaining good combustion, reduces CO₂ as well as NO_x emissions. The proposed heaters and boiler will use oxygen analyzers and draft controls to minimize energy use and emissions of NO_x and CO₂.

Step 3: Rank Technically Feasible Control Options

In order to address the concerns from CO₂ emissions and the potential impact on global warming, there are three possible strategies for the proposed project.

1. The first strategy is to minimize the production of CO₂ from the project's heaters and

boiler. Highly efficient heaters and boilers require less fuel to operate which directly impacts the amount of CO₂ produced. Establishing an aggressive basis for energy recovery and heater efficiency will reduce CO₂ production and the costs to recover it. The following options described in the previous section are technically feasible and are considered an inherent part of the proposed project.

- a. Process integration and heat recovery,
 - b. Stack temperature reduction, and
 - c. Oxygen trim control.
2. The second strategy is the use of low carbon fuels and feedstock, such as RFG and natural gas, instead of high carbon fuels and feedstock such as liquefied petroleum gases and light oils (e.g., naphtha). This strategy can be combined with the first strategy and is planned for implementation.
 3. The third strategy to mitigate the impacts of CO₂ to the environment is CCS. Post-combustion capture, transport, and injection of CO₂ into existing oil fields has been commercially demonstrated. However, for the proposed project it is considered technically infeasible as well as cost infeasible.

Step 4: Process Heater and Boiler CO₂ Controls Cost Impacts Analysis

As noted above, the proposed process heaters and boiler will be fired with the lowest carbon fuels available and will be equipped with the feasible energy efficiency strategies. As a result, no impacts analysis is presented for these two options.

Step 5: Process Heater and Boiler BACT for CO₂e

Having established that CCS is not considered to be economically feasible for the proposed heaters and boiler and that the use of low carbon emitting fuel and energy efficiency is considered feasible, what remains is proposal of BACT limits. CHS proposed GHG permit limits as follows:

- The new #2 Crude Unit Vacuum Heater (005HT0002), Coker Charge Heater (H-7502) and Boiler 13 shall burn only natural gas and RFG;
- Total GHG emissions from the proposed new heaters and shall be less than 236,000 tons per year of CO₂e on a 12-month rolling average basis; and
- Compliance with this limit shall be demonstrated by measuring the fuel flow rate and applying the appropriate emissions factor in Tables C-1 and C-2 of 40 CFR part 98 as published in 78 FR 71950, Nov. 29, 2013 and the Global warming factors published in the same.

The Department determined that rather than include numeric CO₂e limits, the preventative tune-ups required by 40 CFR 63 Subpart DDDDD are more appropriate to minimize CO₂e emissions.

ARM 17.8.752 – Process Heater and Boiler Emissions Control Analysis

In accordance with ARM 17.8.752 - Emission Control Requirements, the owner or operator of a new or modified facility or emitting unit for which a Montana air quality permit is required, shall install the maximum air pollution control capability that is technically

practicable and economically feasible, except that BACT shall be utilized. In accordance with this requirement this section presents a control technology review that addresses the potentially applicable process heater and boiler controls for the non-PSD/NNSR applicable pollutants, SO₂, CO, VOC, PM and H₂SO₄.

ARM 17.8.752 – Process Heater and Boiler SO₂ Controls Analysis

SO₂ emissions from process heaters and boilers are a direct function of the sulfur content of the fuel that is burned. Reduced sulfur compounds in the fuel are readily oxidized to SO₂ and to a much lesser extent SO₃. In the proposed process heaters and boiler, CHS will use RFG or natural gas as the fuel.

Step 1: Identification of Available SO₂ Control Technologies

Emissions of SO₂ from process heaters and boilers can be controlled by fuel specifications or by using post-combustion controls. Fuel specifications limit SO₂ emissions by specifying a maximum allowable sulfur concentration in the gaseous fuels combusted in the process heater or boiler. Post-combustion control for SO₂ involves treating the combustion gases with an alkaline reagent that reacts with the SO₂ to produce a sulfur salt byproduct (e.g., sodium sulfite). This type of post-combustion control process is generally termed Flue Gas Desulfurization (FGD). FGD technology is well-established for sources with relatively high levels of sulfur emissions. It has not been used on refinery process heaters or boilers, generally because fuel gas desulfurization is a more cost-effective means of reducing SO₂ emissions. Each of these control techniques is discussed further below.

Gaseous Fuel Specifications/Use of Natural Gas only. Pipeline quality natural gas has very low sulfur content, generally in the form of mercaptans (at about 4 ppmv) used for “odorization,” and the gas may also contain trace quantities of reduced sulfur compounds (a few grains/100 scf). SO₂ emissions from natural gas-fired equipment are generally considered the lowest practically achievable for that fuel and do not require additional control equipment.

Gaseous Fuel Specifications/Use of Low-sulfur Refinery Gas. Refinery gas typically has higher sulfur content than the natural gas purchased from a pipeline. The RFG sulfur content is dependent on the removal efficiency of the fuel gas amine scrubbing units in a refinery. The proposed process heaters and boiler will use RFG or natural gas as its fuel. To comply with the NSPS subpart Ja standard, CHS will use the existing amine scrubbing system to produce RFG with less than 60 ppmv H₂S, on an annual average basis. On a short-term basis, variability in the operation of the amine scrubbing system may result in spikes in the sulfur concentration of the sweet RFG produced (i.e., as much as 162 ppmv sulfur on a 3-hour average basis).

Flue Gas Desulfurization. FGD is commonly used for control of SO₂ from solid fuel-combustion, such as coal or heavy oil-fired sources. FGD technologies are available and demonstrated in a variety of wet or dry scrubbing configurations. They have demonstrated control efficiencies of up to 95 percent on coal-fired combustion systems.

Step 2: Eliminate Technically Infeasible SO₂ Controls

FGD technology is not commercially demonstrated on small refinery process heaters and boilers because it is not cost effective compared to desulfurizing the fuel gas with the use of

an amine scrubbing system. In addition, removing the sulfur from the fuel rather than the exhaust gas allows much lower SO₂ levels in the exhaust to be achieved. The use of FGD technology would also require the design of the process heater to be significantly altered (i.e., to a mechanical draft design) to provide the flue gas pressure required for adding an FGD system. As a result, FGD technology is removed from consideration.

Step 3: Rank Available SO₂ Controls

The top performing feasible SO₂ control technology is the firing of 100% purchased natural gas in the heaters and boiler, because of the very low sulfur content of natural gas. The next most effective control technology is the use of refinery fuel gas treated to sulfur levels that meet the NSPS Subpart Ja standards. This is the baseline for SO₂ emissions from the proposed process heaters and boiler.

Step 4: Evaluate the SO₂ Control Impacts

Step 5: Proposed ARM 17.8.752 SO₂ Control Requirements

The emission estimates for SO₂ from the proposed heaters and boiler are based on the following proposed SO₂ BACT:

- Refinery fuel gas H₂S content of 60 ppmv (365-day rolling average);
- Refinery fuel gas H₂S content of 162 ppmv (3-hr roll); and
- Compliance shall be demonstrated in accordance with 40 CFR 60.107a(a).

ARM 17.8.752 – Process Heater and Boiler CO and VOC Control Analysis

Carbon monoxide (CO) and volatile organic compounds (VOC) are products of incomplete combustion. The formation of these pollutants is limited by ensuring complete and efficient combustion of the fuel in the heater or boiler. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO and VOC emissions. Measures taken to minimize the formation of NO_x during combustion may inhibit complete combustion, which can increase CO and VOC emissions. Lowering combustion temperatures through staged-combustion to reduce NO_x emissions can be counterproductive with regard to CO and VOC emissions. However, the improved air/fuel mixing that is inherent in newer ULNB designs and control systems help overcome the impact of fuel and/or air staging on CO and VOC emissions. This section presents the CO and VOC BACT analysis for the proposed process heaters and boiler.

Steps 1 and 2: Identification of Available & Feasible CO and VOC Control Technologies

Based on a review of the information provided in the RBLC database, for the conventional process heaters and gas fired boilers, good combustion practices (GCP) is the only control identified. One additional control that is applied to the control of CO and VOC from other types of combustion sources is oxidation catalyst. This control, which is potentially applicable via technology transfer, is also considered.

Good combustion practice (GCP) incorporates the following practices:

- Good combustion,
- Heater/boiler/burner proper design and operation, and
- Use of ULNB technologies.

For the natural gas firing scenario, the summary shows a cost effectiveness of \$0.8 million/ton SO₂ reduced, based on a natural gas price of \$3/MMBtu. As such, this option is not considered cost effective, and is rejected as BACT.

As with other types of fossil fuel-fired systems, combustion control is the most effective means for reducing CO and VOC emissions from gas fired process heaters and boilers. Good combustion is a function of the three “T’s” of combustion: Temperature, Turbulence, and Time where:

- Temperature is high enough to ignite the fuel,
- Turbulence is vigorous enough for the fuel constituents to be exposed to the oxygen, and
- Time is long enough to assure complete combustion.

These components of combustion efficiency are designed into the heaters, boiler and burners to maximize fuel efficiency and reduce operating costs. Therefore, combustion control is accomplished primarily through heater/boiler/burner design and operation. The use of good combustion practices is considered technically feasible and considered further by this analysis.

Oxidation Catalyst has been applied to natural gas-fired combined cycle gas turbines and to a limited extent on boilers located in CO and/or ozone nonattainment areas. Oxidation catalyst is typically a precious metal catalyst (e.g., platinum), which has been applied over a metal or ceramic substrate. The catalyst lowers the activation energy required for the oxidation of CO and VOC so that CO is oxidized at temperatures between 400°F and 1,100°F and that VOC is oxidized at temperatures between 600 and 1100 °F. No chemical reagent addition is required.

Oxidation catalyst technology has been applied at several natural gas-fired boilers and many combustion turbines. Thus, it is considered technically feasible for application on combustion turbines and boilers firing low sulfur fuels (i.e., natural gas). However, in the case of refinery process heaters, use of oxidation catalyst technology is not technically feasible due to leaks that may occur in heater tubes. Although tube leaks are common in boilers and combustion turbine heat recovery steam generators, the fluid leaked is steam or water. Water is not combustible and therefore it passes through the oxidation catalyst without harming the catalyst. In contrast, when a tube leaks in a process heater, hydrocarbons leak into the furnace and end up in the combustion flue gas. The leaked hydrocarbon gases in the combustion flue gas will be oxidized by the catalyst and if present in sufficient concentration, will release enough heat to damage the oxidation catalyst as well as the heater.

Additionally, combustion turbines and boilers equipped with oxidation catalyst are natural gas fired. Natural gas has very low levels of sulfur compounds. Oxidation catalyst oxidizes a significant portion of the sulfur compounds in the fuel to sulfur trioxide which then combines with water to form sulfuric acid mist. This is not a significant issue when firing natural gas. Refinery fuel gas contains significantly more sulfur compounds than natural gas, and as such the use of oxidation catalyst on RFG fired heaters and boilers would result in the formation of a significant amount of sulfuric acid mist in the flue gas. The sulfuric acid mist would corrode the backend of the heater or boiler and increase the emissions of PM₁₀/PM_{2.5} to the atmosphere.

CHS is not aware of any RFG fired heaters or boilers that have been equipped with oxidation catalyst. For the above reasons, the use of oxidation catalyst is considered technically infeasible and not considered further. Only good combustion design and operation is considered to be technically feasible for the control of CO and VOC from the proposed heaters and boiler.

Steps 3-5: Establish Hierarchy and Process Heater CO and VOC BACT Limit

The only technically feasible control option for CO and VOC emissions from process heaters and boilers is good combustion design and operating practices. Therefore, the remainder of this analysis focuses on the achievable emission rates/limits for conventional petroleum refining process heaters and RFG fired boilers.

CO precedents in the RBLC were reviewed for process heater and gas fired boilers. CO permit limits range from 0.02 lb/MMBtu to 0.0824 lb/MMBtu. The majority of the determinations range from 0.037 to 0.04 lb/MMBtu.

Based on a CO emissions rate of 0.04 lb/MMBtu, CHS proposes the following CO BACT emissions limits:

- #2 Crude Unit Vacuum Heater (005HT0002): 1.05 lb/hour,
- Coker Charge Heater (H-7502): 6.43 lb/hour,
- Boiler 13: 8.36 lb/hr, and
- USEPA reference method 10 will be used to demonstrate compliance with the proposed limit.

These limits are consistent with the most recent BACT determinations for similar size refinery process heaters and gas fired boilers.

As noted above, CO and VOC emissions from process heaters and boilers are products of incomplete combustion and are controlled by applying good combustion design and operating practices. As such, we are proposing that the proposed CO BACT limits also serve as the BACT limits for VOC emissions.

ARM 17.8.752 – Process Heater and Boiler PM and H₂SO₄ Controls Analysis

This section provides a PSD BACT analysis for the proposed process heaters and boiler PM and H₂SO₄ emissions. The previously presented PM₁₀ and PM_{2.5} PSD BACT analysis considered both the filterable and condensable components of the PM emissions from the proposed process heaters and boiler. The analysis presented in support of the proposed PSD BACT limits based on 0.0075 lb/MMBtu for the new sources are applicable to the potential PM controls that might be considered in accordance with the ARM 17.8.752 emissions control requirement. As a result, for purposes of compliance with the ARM 17.8.752 requirement the same PSD BACT limits are proposed.

The rate of H₂SO₄ emissions from the proposed process heaters and boiler is directly related to the SO₂ emissions rate and the potentially applicable controls are the same as were considered in the control requirements analysis for the proposed process heaters and boiler. As a result, for purposes of compliance with the ARM 17.8.752 requirement the same SO₂ BACT limits are proposed for purposes of the H₂SO₄ analysis.

Equipment Leaks VOC BACT

The MUE project will include the addition of a number of new connectors, valves, pumps, and similar components for movement of gas and liquid raw materials, intermediates, and products. These components are potential sources of VOC emissions due to leakage from rotary shaft seals, connection interfaces, valve stems, and similar points. The components in the #2 Crude Unit, MHC, DCU, NHT and refinery boiler area will be BACT applicable.

Step 1: Identify Available Control Options

Two information sources were used to identify the potentially applicable VOC equipment leak controls. The first was the RBLC database. The RBLC database has a limited number of entries for refinery sources, because an appropriate NSPS and/or NESHAPS LDAR program is typically adopted as BACT. The second source of information was the EPA docket developed as part of the recent amendments to NSPS Subparts GGG and VV and the promulgation of NSPS Subparts GGGa and VVa.

Based upon a review of these information sources, implementation of an LDAR program in accordance with a pre-existing regulation (i.e., NSPS or NESHAP) and the selection of piping components with construction features that are less likely to allow fugitive VOC emissions were identified as potentially applicable controls. The following sections provide additional discussion related to the contents of an LDAR program and the piping equipment specifications that may be used to reduced emissions from fugitive equipment leaks.

LDAR Program

As noted above, the primary control option selected as BACT in previous determinations was the use of an LDAR program. LDAR programs are also stipulated as a mandatory requirement for new affected facilities under the NSPS and for major sources of HAPs under the refinery MACT regulations. An LDAR program as defined by the possible NSPS and NESHAP regulations includes the following key components:

- Definition of the components included in the affected facility (i.e., pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, valves, pressure relief devices in liquid service and flanges and other connectors, and product accumulator vessels);
- Definition of affected stream criteria (i.e., stream VOC content and vapor pressure). Only equipment contacting fluids that meet specific VOC (and/or HAP) concentration criteria are subject to the NSPS and MACT regulations;
- Inspection frequency (i.e., monthly, quarterly, semiannually, or annually) used to determine if a leak above a defined threshold has occurred;
- Sampling method (i.e., Reference Method 21, 40 CFR Part 60, Appendix A);
- VOC concentrations threshold used to determine if an inspected component is in need of repair;
- For equipment categories not having specific leak concentration thresholds different design and/or control requirements apply. For example, compressors are required to include a barrier fluid system and sampling connection systems are required to be equipped with a closed-purge system routing the fluids back to the process or to a control device; and
- Repair protocol and repair timing requirement.

Piping Equipment Specifications

One available control strategy for fugitive VOC emission control is selecting and installing process piping in a manner which reduces the potential for leaks, or that incorporates emissions control as part of their design. Available control options involving equipment specification or design include the following:

- Pumps – Use of canned, magnetic drive, or diaphragm pumps not having external seals, or pumps designed with double mechanical seals and a barrier fluid. The barrier fluid is at a higher pressure than the process or the fluid seal pot should be routed to a control device.
- Valves – Selection of diaphragm valves or bellows valves with the bellows welded to both the bonnet and stem.
- Flanges and other Connectors – Installation of piping connections that are welded around the complete circumference such that the joint cannot be disassembled by unbolting or unscrewing the components.
- Relief Valves – Routing of relief valve vents to an operating control device or use of rupture disks with a pressure gauge between a valve and the disk to monitor disk integrity.
- Compressors – Use of compressors designed with enclosed distance pieces and venting of the crankcase to a control device.

Step 2: Eliminate Technically Infeasible Control Options

Some of the suggested equipment and process equipment design options that can essentially eliminate fugitive VOC emissions are not technically feasible for the CHS refinery. For example, capturing and routing vapor emissions from all facility pumps and compressors to one or more control devices is impractical and cost-prohibitive due to the large quantity of pumps and compressors that would be involved. Such controls would involve the addition of an enormous quantity of additional vapor piping and equipment, which itself would include fugitive emission sources.

A second possible design option, welding flanges or all other piping connectors together, is not practical because bolted flange connections are usually specified only where they are a necessary part of the facility design. The flanged joints facilitate equipment disassembly for inspection, maintenance, or are necessary for minor process modifications. Also, bolted flanges are necessary when vibration isolators or stress relief devices are needed on a pipe run. Because of cost considerations, flanges are not used when not required for such purposes. A welded butt pipe joint is preferred and less costly than a bolted flange for most pipe section connections.

Selection of seal-less pumps is technically feasible for a limited number of situations. Such pumps are not commercially available in all ranges of flow rate, fluid temperature, and pressure specifications that occur at the CHS refinery. Or, if such pumps are available, their use is cost-prohibitive and does not deliver reasonable cost effectiveness for the quantity of emissions abated.

Finally, the use of bellows valves, enhanced pump seal systems, and use of seal-less pumps was investigated as a possible control alternative for inclusion in the amendment to NSPS subpart GGG. The results of this effort indicated a cost of over \$200,000 per ton of VOC controlled.

Steps 3, 4, and 5: Rank Available Control Technologies, Evaluate Most Effective Controls, and Propose BACT

Based on the above evaluation the use of a pre-existing EPA regulatory-based LDAR program is the remaining technically feasible control option. Following is the hierarchy of existing LDAR programs from most to least stringent:

- 40CFR63 subpart H (i.e., HON NESHAP)
- 40CFR60 subpart GGGa (i.e., Refinery NSPS for Construction, Reconstruction or Modification Commenced after November 7, 2006)
- 40 CFR63 subpart CC (i.e., Refinery NESHAP)
- 40 CFR60 subpart GGG (i.e., Refinery NSPS for Construction, Reconstruction or Modification Commenced after January 4, 1983 and on or before November 7, 2006).
- Uncontrolled

In the process of developing NSPS subpart GGGa, EPA first identified leak definitions for various equipment types. Once completed, EPA evaluated the leak definitions in conjunction with technical feasibility, costs and emission reductions to determine best demonstrated technology (BDT) for each type of equipment. Five sources of information were considered in reviewing the appropriateness of the current NSPS requirements for new sources: (1) Applicable federal regulations; (2) applicable state and local regulations; (3) data from National Enforcement Investigations Center (NEIC) inspections; (4) emissions data provided by industry representatives; and (5) petroleum refinery consent decrees. A key finding in the evaluation was that although the most stringent LDAR program (i.e., HON NESHAP) was cost effective in controlling VOC emissions in SOCM facilities, it was not necessarily cost effective in petroleum refineries for all equipment types. Following are key determinations from the EPA evaluation:

- For petroleum refineries, reducing the NSPS subpart GGG light liquid/gas vapor valve leak definition from 10,000 ppm to 500 ppm and NSPS subpart GGG light liquid pump leak definition from 10,000 ppm to 2000 ppm was determined to be cost-effective at \$1600/ton.
- VOC emission reductions achieved from light liquid/gas vapor valve leak definitions less than 500 ppm were not determined to be cost-effective (i.e., \$16,000/ton for refineries).
- There was no evidence that lowering the leak definition for light liquid pumps below 2000 ppm would achieve significant emission reductions at a reasonable cost.
- For petroleum refineries, reducing the NSPS subpart GGG connectors leak definition from 10,000 ppm to 500 ppm (i.e., NESHAP HON) was not determined to be cost-effective (i.e., \$20,000/ton).

Based on the EPA evaluation, NSPS subpart GGGa was finalized with more stringent requirements than NSPS subpart GGG for light liquid/gas vapor valves and light liquid pumps but did not change the requirements for connectors.

Based on this analysis, VOC BACT for equipment leaks from new components in VOC service is proposed as an effective LDAR program meeting the requirements of NSPS subpart GGGa.

Equipment Leaks GHG BACT

The proposed project will include addition of a number of new connectors, valves, pumps, and similar components for movement of gas and liquid raw materials, intermediates, and feedstocks. These components are potential sources of methane (CH₄) emissions due to leakage from rotary shaft seals, connection interfaces, valve stems, and similar points. Two sources of GHG emissions associated with equipment leaks must be considered: 1) methane contained in the VOC/HAP leaks associated with process units, and 2) potential leaks from the piping used to deliver RFG and natural gas to the project heaters and boiler, and other non-VOC/HAP containing process streams as defined by NSPS/NESHAP leak detection and repair (LDAR) programs. Methane emissions from VOC/HAP leaks associated with the proposed project's modified process units will be effectively controlled by VOC/HAP LDAR programs that will be required by the appropriate NSPS and NESHAP LDAR regulations. This leaves the non-VOC/HAP, methane containing process streams to be evaluated for GHG BACT.

Steps 1-4: GHG Equipment Leaks

Implementation of an LDAR program in accordance with a pre-existing regulation for VOCs and HAPs (i.e., NSPS or NESHAP) and the selection of piping components with construction features that are less likely to allow fugitive emissions are potentially applicable methane controls. In addition, the prior sections discussion pertaining to VOC equipment leaks is directly applicable to methane equipment leaks in the natural gas and RFG piping. As a result, it is not repeated.

Note that the cost effectiveness criteria used by EPA in the development of the NSPS subpart GGGa LDAR program is not applicable to the control of methane emissions from the same piping components. For example, while \$1600/ton is deemed cost effective as BDT for VOC under the NSPS development process, the cost effectiveness of CO₂e control is not deemed cost feasible for cost-effectiveness values greater than ~\$50/ton. The \$1600/ton cost is well above the range of cost-effectiveness values considered to be reasonable and acceptable in BACT determinations for control of GHG emissions. For example:

- In making the GHG BACT determination for Copano Processing, U.S. EPA determined that control of GHG emissions at a cost of \$54/ton is not BACT because it is "economically prohibitive."
- In making the GHG BACT determination for the City of Palmdale, U.S. EPA determined that control of GHG emissions at a cost of \$45/ton is not BACT because it is "economically infeasible."
- In making the GHG BACT determination for Freeport LNG Development, L.P.'s Freeport LNG Liquefaction Project, U.S. EPA determined that control of GHG emissions from the amine treatment units was cost prohibitive; the cost effectiveness of the control option under consideration was estimated at approximately \$14/ton of CO₂ sequestered.

Step 5: Establish GHG Equipment Leak BACT

For the proposed project, the VOC BACT analysis above proposes that all new and modified components will be subject to the requirements of an effective VOC LDAR program meeting the requirements of NSPS subpart GGGa. However, the requirements of the NSPS subpart GGGa LDAR program do not apply to components that contain less than 10 percent VOC such as natural gas to the project heaters and boiler. As BACT for methane emissions from equipment leaks, CHS

proposes to include the piping employed to natural gas to the proposed project heaters and boiler under the NSPS subpart GGa LDAR program. This is because the expansion of an already required VOC LDAR program to address the non-VOC process streams for the proposed project is considered BACT for methane. This determination is consistent with the previous precedents where the VOC/HAP LDAR program identified as BACT/LAER for VOC was determined to be BACT for methane. Proposing a more stringent LDAR program than proposed for VOC/HAP LDAR for the new/modified process equipment would be cost ineffective for methane due to the low cost benefit threshold for the control of GHGs.

NOx Limit Review for Boilers #11 and #12

The objective of this review is to provide the necessary evaluation to modify the existing NOx BACT limits that are applicable to Boilers 11 and 12 such that the full steam-generating capacity of the boilers can be utilized, particularly during short-term periods. This analysis considers the increase in NOx limits to be a change in the method of operation and therefore is also treated as a modification. The request to change the NOx limits for Boilers #11 and #12 is un-related to the MUE project but is included in the application.

This section provides the background on the NOx limit for Boilers #11 and #12, a new source review analysis, a regulatory applicability determination, BACT review, and an air quality impacts discussion.

Boilers #11 and #12 were commissioned in 2007 and 2009, respectively and are each rated for 209.1 MMBtu/hr (HHV) and include ULNB and FGR to control NOx emissions. The original BACT hourly limits were established using a vendor guaranteed emission factor of 0.02 lb/MMBtu. The guaranteed vendor NOx limits are unable to be achieved when the boilers are operated near their full capacity and require CHS to limit boiler production in order to achieve the hourly NOx limits. In order to revise the NOx limits, a new emission factor based on the RBLC database and a determination of applicability of a higher emission rate is presented here. Actual emission rates for these boilers across all conditions has been reported to be between 0.015 to 0.035 lb/MMBtu. An analysis presented by CHS demonstrated that as the hydrogen content within the RFG gas increases it results in an increase in the NOx emissions on the boiler. This is best explained by the fact that a higher hydrogen content results in a higher flame temperature than methane which is the primary component in the RFG. Therefore, the normal variability of hydrogen concentration within the RFG results in the inability to stay below the NOx hourly limits. The higher concentration of hydrogen is beneficial since hydrogen is a clean burning fuel with no formation of CO₂ when combusted. Therefore, trying to reduce the hydrogen concentration within the RFG is not a recommended solution. The boilers are further limited by their challenge to provide only so much FGR to help keep the flame temperature down. The RFG hydrogen concentration and variability was not well known at the time the boilers were constructed and the higher hydrogen concentration cannot be fully mitigated by the FGR as the recirculation rate is limited by the equipment design.

Boiler #11 and Boiler #12 were each considered minor modifications under MAQP #1821-21 and were not part of a netting analysis. The RLBC for the most recent NOx emission limits typically range from 0.015 lb/MMBtu to 0.040 lb/MMBtu and CHS has proposed the basis of the emission limit be based on 0.030 lb/MMBtu. This is consistent with the BACT analysis for Boiler #13. Given the variability of the hydrogen concentration within the RFG, an emission rate of 0.030 lb/MMBtu is considered a BACT level consistent with the most recent determinations, particularly given the boilers, at the time of this permit action are now eleven to thirteen years old. Modification of the existing BACT limit to an emission rate of 0.030 lb/MMBtu would provide for total potential emissions of 27.48 tpy for each boiler. This is based on 0.030 lb/MMBtu/hr*209.1 MMBtu*8,760

hrs/2000. Baseline emissions for each Boiler #11 and Boiler #12 for the most recent representative period are 10.10, and 7.05, tpy respectively. When originally permitted, each boiler would still have been below the significance threshold of 40 tpy even after the proposed increase from 4.18 lb/hr to 6.27 lb/hr. is included. Each boiler would therefore still be considered a minor modification and not subject to PSD for NOx. The proposed hourly mass limit of 6.27 lb/hr for each boiler on a rolling 365-day average is appropriate and accepted for new NOx limits going forward. CHS proposed no annual limit for each boiler but the Department included annual rolling 12-calendar month totals for each boiler. These are identical to the 0.030 lb/MMBtu basis and are included to manage overall emission increases associated with the change.

Boiler 11	
Current Condition	Proposed Condition
18.3 tons/rolling 12-calendar month total (ARM 17.8.752)	27.5 tons/rolling 12-calendar month total (ARM 17.8.752)
4.18 lb/hr (ARM 17.8.752)	6.27 lb/hr ⁵ , rolling 365-day average (ARM 17.8.752)
Boiler 12	
Current Condition	Proposed Condition
0.02 lb/MMBtu-HHV, on a rolling 365-calendar day average (ARM 17.8.752)	None
18.31 tons/rolling 12-calendar month total (ARM 17.8.752)	27.5 tons/rolling 12-calendar month total (ARM 17.8.752)
4.18 lb/hr (ARM 17.8.752)	6.27 lb/hr, rolling 365-day average (ARM 17.8.752)

5 0.03 lb NOx/MMBtu (HHV) times 209.1 MMBtu (HHV) /hr

IV. Emission Inventory for MUE Project

Project related increases in tons per year for the MUE project are shown in the below table.

Emission Units	SO ₂	NO _x	PM-10	PM-2.5	PM	VOC	CO	H ₂ SO ₄	CO _{2e}
New									
#2 CU Vacuum Heater (005HT0002)	0.84	4.59	0.86	0.86	0.21	0.62	4.59	0.13	15,680
Coker Charge Heater H-7502	5.92	28.17	5.25	5.25	1.31	3.80	28.17	0.90	95,216
Boiler 13	6.72	27.47	6.82	6.82	1.71	4.94	36.63	1.02	125,103
Modified									
Refinery Equipment						5.22			
Project Affected									
Process Heaters	0.23	14.97	1.60	1.60	1.60	0.45	7.65	0.65	26,698
FCCU Regenerator	0.19	1.10	1.02	1.02	1.17	0.50	1.40	0.03	5,720
Coke Drum Steam Vent			0.96	0.96	0.96	4.01			
Coke Handling/Trucking			1.08	0.14	4.03				
Storage Tanks						3.72			
Sulfur Recovery Units	8.55	1.74	0.09	0.09	0.09	0.06	2.21	1.30	1,413
2SSWS Ammonia Combustor	0.01	0.31	0.04	0.04	0.04	0.03	0.42	0.00	615
Hydrogen Production	0.14	9.19	2.53	2.53	2.53	0.07	0.48	0.02	253,527
Loading Facilities	0.00	0.09	0.00	0.00	0.00	1.15	0.82	0.00	159
Totals									
	22.6	87.6	20.3	19.3	13.7	24.6	82.4	4.0	524,131
Significance Threshold	40	40	15	10	25	40	100	7	
Significant?	NO	YES	YES	YES	NO	NO	NO	NO	

Emission Inventory for Boiler #11 and Boiler #12 (tpy)

	NO _x	SO ₂	PM & PM _{10/2.5}	CO	VOC
Boiler 11 PTE, TPY	27.48	8.59	4.16	36.63	4.83
Boiler 12 PTE, TPY	27.48	5.84	4.58	36.63	4.81
PSD Thresholds, TPY	40	40	25/15/10	100	40

V. Existing Air Quality

The CHS refinery facility is located primarily in Section 16 of Township 2 South, Range 24 East, Yellowstone County, which is a 24-hour sulfur dioxide (SO₂) nonattainment area (NAA) for the 1971 primary SO₂ NAAQS. The NAA status was published in the Federal Register (FR) on March 3, 1978 (43 FR 9010). This NAA is a 2 kilometer (km) (1.2 miles, mi) radius circle centered on the geographic center of the refinery as described in a Department letter to the U.S. Environmental Protection Agency (USEPA) dated April 3, 1991.

The CHS refinery is located about 18.0 km (11.0 mi) southwest of Billings, MT. A prior Billings 1-hour SO₂ NAA was about 23.8 km (14.8 mi) northeast of the refinery. This NAA was designated in regard to the 2010 primary SO₂ NAAQS (78 FR 50 47191, August 5, 2013). The nonattainment area has recently been redesignated as attainment with the 2010 primary SO₂ NAAQS (see 40 CFR 52.1398).

A limited carbon monoxide maintenance plan area also exists in the Billings area, about 17.4 km (10.8 mi) away. Otherwise, the area is currently designated as “Unclassifiable/Attainment” for all other air quality criteria pollutants (40 CFR 81.327). The closest Class I area is the Northern Cheyenne Indian Reservation (NCIR), a non-federal Class I area, about 136 km (85 mi) east of the refinery.

VI. Air Quality Impacts

Ambient Air Impact Analysis

The CHS Laurel refinery is a major stationary source and a listed source under the Prevention of Significant Deterioration (PSD) regulations of 40 CFR 52.21 in addition to state regulations (ARM 17.8.801 and ARM 17.8.818).

RTP Environmental Associates conducted air quality modeling for the proposed Multi-Unit Expansion Project as part of the CHS air quality permit application. This ambient air impact analysis was conducted, pursuant to the requirements of ARM 17.8.820 and ARM 17.8.822 to demonstrate that the proposed modification would not cause or contribute to a violation of any NAAQS, Montana Ambient Air Quality Standards (“MAAQS”) or applicable PSD increment (PSD Class II Significant Impact Analysis); pursuant to ARM 17.8.825, and ARM 17.8.1106 to show that the project does not cause or contribute to any adverse impact on visibility within any federal Class I areas (PSD Class I Air Quality Analysis and PSD Class I Significant Impact Analysis); and pursuant to ARM 17.8.824 to show that the project does not cause or contribute to additional impacts to soils, vegetation, and growth (Additional Impact Analysis).

The MUE project emission increases are above the significant emission rates (SERs) listed in ARM 17.8.801(28) for nitrogen dioxides (NO₂), particulate matter with an aerodynamic diameter of less than 10 µm (PM₁₀) and particulate matter with an aerodynamic diameter of less than 2.5 µm (PM_{2.5}). Emission increases were first modeled to determine if any receptors exceeded the Significant Impact Levels (SILs), presented in Table VI-1. For those pollutants and averaging times that exceed the applicable SILs, CHS was required to demonstrate compliance with NAAQS, MAAQS, and PSD Increments, also presented in Table VI-1. Significant Monitoring Concentrations (SMCs) are also displayed. For this project, NO₂ 1-hour Class II SILs were exceeded, which required a NAAQS analysis. Note that there is no 1-hour NO₂ increment. As a result, no Increment analysis was conducted.

Table VI-1 Applicable NAAQS, MAAQS, SILs and SMCs

Pollutant	Averaging Period	Class I SIL ($\mu\text{g}/\text{m}^3$)	Class II SIL ($\mu\text{g}/\text{m}^3$)	Primary NAAQS ($\mu\text{g}/\text{m}^3$)	MAAQS ($\mu\text{g}/\text{m}^3$) ^a	Class I Increment ($\mu\text{g}/\text{m}^3$)	Class II Increment ($\mu\text{g}/\text{m}^3$)	SMC ($\mu\text{g}/\text{m}^3$)
PM	30-day	-	-	-	10 g/m^2	-	-	-
PM ₁₀	24-hour	0.3	5.0	150	150	8	30	10
	Annual	0.2	1.0	-	50	4	17	-
PM _{2.5}	24-hour	0.27	1.2	35	-	2	9	4
	Annual	0.051	0.2	12	-	1	4	-
NO ₂	1-hour	-	7.5	188	565	-	-	-
	Annual	0.1	1.0	100	94	2.5	25	14

^aUnits are $\mu\text{g}/\text{m}^3$ unless otherwise noted.

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

- AERMOD version 19191: Air dispersion model.
- AERMET version 19191: processes NWS meteorological data for input to AERMOD.
- AERMINUTE version 15272: processes 1-minute National Weather Service (NWS) wind data to generate hourly average winds for input to AERMET.
- AERSURFACE version 13016: processes 2011 National Land Cover Data surface characteristics for input to AERMET.
- AERMAP version 18081: Processes National Elevation Data from the United States Geological Survey to determine elevation of sources and receptors for input into AERMOD.
- BPIPPRM version 04274: characterizes building downwash for input to AERMOD.
- Oris Solution's BEEST Graphical User Interface, Version 12.01.

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

Five years of meteorological data (2014-2018) ready for use in AERMOD was constructed using representative surface and upper air data. Surface air data was obtained from the closest NWS station, which is located approximately 24 km to the southwest of the project site, at the Billings Logan International Airport (KBIL – WMO 726770, WBAN 24033). This NWS station also provided the automated surface observing system (ASOS) one-minute data used with AERMINUTE. The Great Falls Upper Air station (WMO 72776, WBAN 04102) was used for upper air data. The ADJ_U* option was employed in AERMET to account for stable, low wind speeds.

A series of three nested receptor grids were used in the model to calculate the ambient air impacts around the project location. Discrete receptors were placed at 50 m spacing along the site's ambient boundary, 100 m spacing from the ambient boundary to 1500 m from the site, 500 m spacing from 1500 m to 15 km from the site, and 1000 m spacing from 15 km to

25 km from the site. Due to maximum concentrations found at higher elevations to the northwest and southeast of the refinery, receptors were placed at a spacing of 100 m in these areas. The number of receptors totaled 20,700 locations. Only the significantly impacted receptors (receptors with modeled concentrations equal to or greater than their respective SILs) were used for the NAAQS/MAAQS analyses.

Ambient, background pollutant concentrations are needed to establish a representative background concentration to complete the NAAQS portion of the Source Impact Analysis of 40 CFR 52.21(k). The background concentrations are added to the modeled concentrations to assess NAAQS/MAAQS compliance. Ambient pollutant concentrations are also needed to fulfill the Air Quality Analysis requirement of 40 CFR 52.21(m).

The following monitoring sites were identified for use as background concentrations. The PM_{2.5} data was stitched together from two sites in Billings, the St. Lukes monitor (30-111-0085) from January 2016 through December 2017, and the Lockwood monitor (30-111-0087) from December 2017 through December 2018. The background concentrations were calculated both including and excluding exceptional events (wildfires, windblown dust, etc.), to illustrate the impacts of wildfires on the background levels. PM₁₀ and NO₂ background concentrations were calculated from the closest available site with recent data (2016-2018) for those pollutants, which was the Lewistown monitor (30-027-0006). These background concentrations are displayed in Table VI-2.

Table VI-2 PM_{2.5} Background Concentrations

Pollutant	Averaging Time	Background Conc. (µg/m ³) ⁽¹⁾	Background Conc. (µg/m ³) ⁽²⁾	Basis	Site
PM _{2.5}	24-hour	24.2	16.1	Avg. 98%-ile of yearly 24-hour values	Billings – St. Lukes (30-111-0085) and Lockwood (30-111-0087)
	Annual	7.5	6.5	3-year Annual avg.	
PM ₁₀	24-hour	65	32	Average of yearly 2nd max	Lewistown (30-027-0006)
	Annual	10	8.5	3-year Annual avg.	
NO ₂	1-hour	17.0 (9.0 ppb)	17.0 (9.0 ppb)	Avg. 98%-ile of yearly 1-hour daily max values	
	Annual	1.0 (0.55 ppb)	1.0 (0.55 ppb)	Max annual average	

⁽¹⁾Data includes all exceptional event data in the calculations.

⁽²⁾ Data excludes all exceptional event data in the calculations.

Data with exceptional events removed was used for all purposes in this analysis. The data, representative of the Billings metropolitan area fulfills the preconstruction and post-construction monitoring requirements of ARM 17.8.822.

Secondary PM_{2.5} impacts consisting primarily of NO_x and SO₂ precursor emissions due to the project cannot be evaluated with the AERMOD dispersion model since it cannot take chemical transformations into account. CHS assessed secondary PM_{2.5} formation using hypothetical source precursor pollutant (NO_x and SO₂) emission rate data and secondary PM_{2.5} photochemical modeling results that were utilized by the EPA to develop Modeled Emission Rates for Precursors (MERPs) for NO_x and SO₂. Photochemical modeling results for the appropriate hypothetical source (Source 11 from Yellowstone County) were scaled by the MUE project emission rate, in accordance with latest MERPs guidance. These impacts were added to all PM_{2.5} AERMOD modeling results, as displayed in the applicable tables below.

In addition, VOC and NO_x emissions were evaluated using EPA's MERPS guidance to assess the potential for additional ozone formation. Ozone impacts were determined to be insignificant (less than 8-hour ozone SIL).

For the NO₂ modeling analyses, Tier 2 (Ambient Ratio Method, ARM2) was employed in AERMOD, with the EPA default minimum and maximum ambient ratios of 0.5 and 0.9, respectively (ratio of NO₂/NO_x).

Source parameters were provided by CHS, parameters were modeled as either "point" or "volume" sources in AERMOD and their descriptions are displayed in Table VI-3. Fugitive emissions and haul roads were modeled as volume sources.

Table VI-3 Onsite Source Descriptions

SrcID	Source Description (As Identified in Permit)	Source Category
2CVHTR1	No. 2 Crude Heater (new location)	New
2CVHTR1O	No. 2 Crude Heater (original location)	Shutdown Source
2CVHTR2	No. 2 Vacuum Heater	Shutdown Source
407401	Zone D	Project Affected
5HT0002	No. 2 CU Vacuum Heater	New
ALKYHTR1	Alky Oil Heater	Project Affected
ASPROHTR	#1 Asphalt/RO Loading Heater	Other Existing Source
BOIL10	No. 10 Boiler	Other Existing Source
BOIL12	No. 12 Boiler	Other Existing Source
BOIL13	New Boiler (Boiler No. 13)	New
BOIL9	No. 9 Boiler	Other Existing Source
CKESTM	Coker Drum Steam Vent	Project Affected
CKRDPV1- CKRDPV27	Coke Haul Road Paved Segments 1-27	Other Existing Source
CKRDUP1- CKRDUP28	Coke Haul Road Unpaved Segments 1-28	Other Existing Source
COKEHAN	Coke Handling	Project Affected
COKEPILE	Coke Storage Pile	Project Affected
CVHTR1	Crude Preheater (Petrochem)	Other Existing Source
CVHTR2	Main Crude Heater (RFG)	Other Existing Source
CVHTR4	No. 1 Vacuum Heater	Other Existing Source
FCCHTR1N	New FCC Feed Preheater	Project Affected

FCCVSSL1	FCC Process	Project Affected
FL7201	Coker Unit Flare	Other Existing Source
H1001	H2 Plant H-1001 Heater	Project Affected
H101	H-101 Reformer Heater	Project Affected
H102	H-102 Reformer Heater	Project Affected
H201	H-201 Charge Heater	Project Affected
H202	H-202 Charge Heater	Project Affected
H7501	Coker Charge Heater	Other Existing Source
H7502	Coker Charge Heater #2	New
H8301	NHT Charge Heater	Other Existing Source
H8302	No. 1 Naphtha Unifiner Stripper Reboiler	Other Existing Source
H8303	NHT No. 2 Stripper Reboiler	Other Existing Source
H8304	NHT Splitter Reboiler	Other Existing Source
H901	ULSD Heater H-901	Other Existing Source
H902	ULSD Heater H-902	Other Existing Source
HPPREF	#3 Hydrogen Plant Reformer	Project Affected
INC701	NH3 Incinerator	Project Affected
NEWFLR	New Flare	Other Existing Source
PHTR1	Platformer Heater Four Sections	Project Affected
PHTR2	Platformer Debutanizer Heater	Project Affected
PHTR3	Platformer Splitter Reboiler	Project Affected
RBOIL	No. 11 Boiler	Other Existing Source
RVCU	Railcar Light Product Loading VCU	Project Affected
SRUAUX4	Zone A SRU-TGTU-TGI	Project Affected
TRKVCU	Truck Light Product Loading VCU	Other Existing Source
ZONEESRU	Coker Unit SRU through TGI	Project Affected

PSD Class II Significant Impact Analysis

CHS performed an initial significant impact analysis, in which the calculated maximum impacts were determined for each pollutant with an emissions increase that exceeds the PSD SER. These impacts determine the net change in air quality resulting from the proposed project. Negative emissions were modeled for the shutdown and from the original location of a relocated source.

Modeled PM₁₀, PM_{2.5}, and NO₂ Class II SIL results are presented in Table VI-4. NO₂ impacts exceeded the 1-hour SIL, so a NAAQS analysis was performed.

Table VI-4 Class II Significant Impact Analysis Results

Pollutant	Avg. Period	Model Conc. (µg/m³)	Secondary Impact Conc. (µg/m³)	Total Conc. (µg/m³)	SIL (µg/m³)	Max Distance to a Significant Impact (km)
PM ₁₀	24-hour ⁽¹⁾	1.26	-	1.26	5.0	-
	Annual ⁽²⁾	0.93	-	0.93	1.0	-
PM _{2.5}	24-hour ⁽³⁾	1.14	0.025	1.16	1.2	-

	Annual ⁽⁴⁾	0.18	0.001	0.18	0.2	-
NO ₂	1-hour ⁽⁵⁾	13.4	-	13.4	7.5	14.7
	Annual ⁽⁶⁾	0.48	-	0.48	1.0	-

⁽¹⁾Modeled concentration is the maximum 24-hour concentration in a 5-year period.

⁽²⁾Modeled concentration is the maximum annual concentration in a 5-year period.

⁽³⁾Modeled concentration is the maximum 5-year average 24-hour concentration.

⁽⁴⁾Modeled concentration is the maximum 5-year average annual concentration.

⁽⁵⁾Modeled concentration is the maximum 5-year average 1-hour concentration.

⁽⁶⁾Modeled concentration is the maximum annual concentration in a 5-year period.

For the NAAQS analysis, CHS elected to conservatively include all offsite source emissions within a 50 km screening area. CHS performed this analysis with emissions data provided by MDEQ. The offsite source descriptions are shown in Table VI-5.

Table VI-5 Offsite Source Descriptions

SrcID	Source Description
OFFSTE11	Western Sugar Erie City Boiler #1
OFFSTE12	Western Sugar Boiler 2-4
OFFSTE14	Western Sugar Combined Pulp Dryers
OFFSTE17	Phillips 66 - Boilers
OFFSTE19	Phillips 66 - Heaters
OFFSTE2	Western Emulsions
OFFSTE20	Phillips 66 FCCU
OFFSTE26	Phillips 66 Charge Heater H-9501
OFFSTE27	Phillips 66 #5 HDS Fract. Reboil H9502
OFFSTE28	Phillips 66 #2 H2 Plant Heater H-9701
OFFSTE3	Laurel East Veterinary Services
OFFSTE31	Phillips Worst Case Stack
OFFSTE32	Yellowstone Power Plant
OFFSTE33	Billings Wastewater Plant
OFFSTE34	Montana Sulphur
OFFSTE35	Exxon (worst case stk)
OFFSTE36	Stillwater Mining Co
OFFSTE37	Lake Basin Compressor Station
OFFSTE38	Billings Landfill
OFFSTE40	Heights Family Funeral
OFFSTE41	Best Friends Animal Hospital
OFFSTE5	United States Bakery
OFFSTE6	Billings Animal Control
OFFSTE7	Yellowstone Valley Veterinary Inc
OFFSTE8	Cremation and Funeral Gallery
OFFSTE9	Dahl Funeral Chapel Billings, Inc.

New, modified, and project-impacted sources used potential to emit emission rates; other existing sources (including offsite) were given actual emissions appropriate to each averaging period, averaged over 2017 and 2018.

The results of the NAAQS analysis are shown in Table VI-6, which show that the modeled emissions comply with NO₂ NAAQS standard. The modeled results also indicate compliance with the NO₂ MAAQS standard.

Table VI-6 NAAQS Analysis Results

Pollutant	Avg. Period	Model Conc. (µg/m ³)	Background Concentration (µg/m ³)	Total Conc. (µg/m ³)	Primary NAAQS (µg/m ³)	% of NAAQS
NO ₂	1-hour	54 ⁽¹⁾	17	71	188	38%

⁽¹⁾The receptor that had the 8th-highest annual max daily 1-hr concentrations, averaged over 5 years.

The other applicable MAAQS (ARM 17.8 Subchapter 2) for this project are the PM₁₀ 24-hour and annual MAAQS, and the PM MAAQS for settle particulate matter displayed in Table VI-1. The PM₁₀ MAAQS analysis was not required due to the fact that the PM₁₀ SILs were not exceeded. CHS cited the EPA rulemaking replacing the total suspended particulate (TSP) NAAQS with the PM₁₀ NAAQS. Specifically, EPA stated that there is no convincing evidence of significant adverse soiling and nuisance at TSP levels below 90-100 µg/m³. Due to the fact that project PM₁₀ increases will be insignificant and the PM₁₀ NAAQS replaced TSP standards for protecting public health, this suggests compliance with the PM MAAQS.

PSD Class I Significant Impact Analysis

A significant impact analysis was performed to evaluate whether the project's net emissions increases of PM₁₀ and PM_{2.5} would indicate a modeled impact in the area near the site that would exceed applicable PSD Class I SILs. Receptors were placed in a circle in 1-degree intervals at 50 km from the project site, and the maximum modeled impact at this 50 km arc was compared to the applicable Class I SIL. All nearby Class I areas are located greater than 100 km from the site. The results of this analysis are presented in Table VI-7.

Table VI-7 Class I Significant Impact Analysis Results

Pollutant	Avg. Period	Model Conc. (µg/m ³)	Secondary Impact Conc. (µg/m ³)	Total Conc. (µg/m ³)	SIL (µg/m ³)
PM ₁₀	24-hour ⁽¹⁾	0.011	-	0.011	0.30
	Annual ⁽²⁾	0.002	-	0.002	0.20
PM _{2.5}	24-hour ⁽³⁾	0.008	0.025	0.033	0.27
	Annual ⁽⁴⁾	0.002	0.001	0.003	0.05
NO ₂	Annual	0.009	-	0.009	0.10

⁽¹⁾Modeled concentration is the maximum 24-hour concentration in a 5-year period.

⁽²⁾Modeled concentration is the maximum annual concentration in a 5-year period.

⁽³⁾Modeled concentration is the maximum 5-year average 24-hour concentration.

⁽⁴⁾Modeled concentration is the maximum 5-year average annual concentration.

PSD Class I Air Quality Analysis

In accordance with the provisions of ARM 17.8.825 and ARM 17.8.1106 (visibility only), CHS evaluated the potential for the MUE to impact the air quality related values (AQRVs) of nearby Class I areas.

A “Q/d” screening analysis was performed by summing together the maximum emissions increases of NO_x, PM₁₀, and SO₂ (Q) and dividing that by the minimum distance (d) to the Class I area. The results are shown in Table VI-8. Because each Q/d result is considerably less than 10, the MUE is not expected to negatively impact the AQRVs of the areas.

Table VI-8 Class I “Q/d” results

Class I Area	Q (tpy)	d (km)	“Q/d”
North Absaroka Wilderness Area	71.8	113	0.637
Yellowstone National Park	71.8	119	0.601
Northern Cheyenne Reservation	71.8	136	0.528
Washakie Wilderness Area	71.8	118	0.608
UL Bend Wilderness Area	71.8	212	0.339
Teton Wilderness Area	71.8	174	0.414
Grand Teton National Park	71.8	234	0.307
Fitzpatrick Wilderness Area	71.8	251	0.286
Gates of the Mountains Wilderness Area	71.8	264	0.272
Red Rock Lakes Wilderness Area	71.8	251	0.286
Bridger Wilderness Area	71.8	264	0.271

In addition, as stated in ARM 17.8.1110(5), the federal Class I areas visibility monitoring requirements of ARM 17.8.1110 can be waived if “V” is less than 0.5. The projected increases for the MUE produce results less than 0.5 for all Class I areas.

Additional Impact Analysis

No associated permanent industrial growth was noted to occur from the MUE due to the short term, temporary construction impacts, and the fact that the majority of the additional product volume will be shipped by pipeline, with no anticipated significant increases in railcar and truck shipments.

Class II visibility impacts were also evaluated at the Indian Caves State Park using VISCREEN, and the results show that the MUE project would not impair local visibility. CHS provided a soils and vegetation analysis that demonstrates that emissions increases are not expected to have a harmful impact on soils and vegetation in the area of the site.

The analysis conforms to the modeling procedures outlined in the Environmental Protection Agency's Guideline on Air Quality Models (Guideline) and associated EPA modeling policy and guidance as well as the modeling protocol submitted to the MDEQ on January 8, 2020.

The Department determined that the project-related PM, PM₁₀ and PM_{2.5}, and NO₂ increases (with offsite facility NO₂ source emissions) will not cause or contribute to a federal or state ambient air quality standard, will not exceed a PSD Class I or II increment, will protect Class I AQRVs including visibility, and will not impair the surrounding environment such as community/industrial growth, soils, crops, and vegetation. This decision was based on the air dispersion modeling with qualitative/quantitative analyses. The full modeling analysis submitted with the MAQP application is on file with the Department.

VII. Taking or Damaging Implication Analysis

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

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

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

VIII. Environmental Assessment

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

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: CHS Inc.
Laurel Refinery
P.O. Box 909
Laurel, MT 59044-0909

Montana Air Quality Permit (MAQP) Number: 1821-43

Draft EA Issued: 5/18/2020

Final EA Issued: 6/23/2020

Permit Final: 7/9/2020

1. *Legal Description of Site:* South ½, Section 16, Township 2 South, Range 24 East in Yellowstone County.
2. *Description of Project:* With this application, CHS Inc. is proposing to implement a refinery expansion identified as the Multiple Unit Expansion (MUE) Project. The MUE project would provide for two new process heaters and a new steam generating boiler as well as modifications within existing process areas. Within the application, Boiler #11 and Boiler #12 NOx limits are revised from permit limits adopted in 2006 and 2008, respectively through a new BACT analysis relying on the most recent entries in the RACT/BACT/LAER (RBLC) database. Previous limits were established by vendor guarantees and have since been determined to be unachievable since start-up during certain desired operating scenarios. Finally, several administrative changes/clarifications are being incorporated including moving to electronic submittal of compliance reports.
3. *Objectives of Project:* Increase capacity in the #2 Crude Unit and to provide additional crude processing flexibility. The project replaces the atmospheric column within the #2 Crude Unit and replaces an existing heater. The Mild Hydrocracker would be modified to increase its capacity as would the Delayed Coker.
4. *Alternatives Considered:* In addition to the proposed action, the Department also considered the “no-action” alternative. The “no-action” alternative would deny issuance of the MAQP to the proposed facility. However, the Department does not consider the “no-action” alternative to be appropriate because CHS demonstrated compliance with all applicable rules and regulations as required for permit issuance. If the “no-action” alternative were implemented, no emission increases would occur. Therefore, the “no-action” alternative was eliminated from further consideration.

5. *A listing of mitigation, stipulations and other controls:* A list of enforceable permit conditions and a complete permit analysis, including BACT determinations, would be contained in MAQP #1821-43.
6. *Regulatory effects on private property:* The Department considered alternatives to the conditions imposed in this permit as part of the permit development. The Department determined that the permit conditions are reasonably necessary to ensure compliance with applicable requirements and to demonstrate compliance with those requirements and do not unduly restrict private property rights.
7. *The following summarizes the potential physical and biological effects of the proposed project on the human environment for the thermal combustor project. The "no action alternative" was discussed previously.*

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*

This permit action would provide for two new heaters and a new boiler as well as modification of other process area equipment. Incremental increases also occur at non-modified equipment. No discernible impact to terrestrial and aquatic life and habitats as a result of the changes permitted in MAQP #1821-43 would be expected. Any impacts would be expected to be minor.

B. *Water Quality, Quantity, and Distribution*

This permit action would provide for two new heaters and a new boiler as well as modification of other process area equipment. Incremental increases also occur at non-modified equipment. The emissions changes would not be expected to result in any discernible impact to water quality, quantity, and distribution. Impacts to water quality would be expected to be minor.

C. *Geology and Soil Quality, Stability, and Moisture*

The proposed changes occur within the existing refinery property boundary on an area previously disturbed. Impacts to geology and soil quality, stability, and moisture are not expected with this action.

D. *Vegetation Cover, Quantity, and Quality*

This permit action would provide for two new heaters and a new boiler as well as modification of other process area equipment. Incremental increases also occur at non-modified equipment. The emissions changes would not be expected to result in any discernible impact to vegetation cover, quantity, and quality. No new disturbance occurs with this action.

E. *Aesthetics*

The proposed changes will not change the aesthetics of the industrial site. No change would occur with the current aesthetics.

F. *Air Quality*

This permit action would provide for two new heaters and a new boiler as well as modification of other process area equipment. Incremental emission increases also may occur at non-modified equipment. The changes would not be expected to result in any more than minor impacts to current air quality.

G. *Unique Endangered, Fragile, or Limited Environmental Resources*

No discernible change in impacts to any unique endangered, fragile, or limited environmental resources would be expected as a result of this project. Any impacts to unique endangered, fragile, or limited environmental resources as a result of this project would be expected to be minor.

H. *Demands on Environmental Resource of Water, Air, and Energy*

As discussed in Section F. above, no more than minor impacts to current air quality would be expected as a result of this project. As discussed in Section B. above, no more than minor impacts would be expected to occur. Some increase in energy demands would be expected as a result of the increased refinery capacity. Demands on resources of water, air, and energy would be expected to be minor.

I. *Historical and Archaeological Sites*

The permitting action would not result in new ground disturbance. No impacts to any historical and archaeological sites would be expected to occur. The site is extremely industrial in nature due to the complexity of refining operations.

J. *Cumulative and Secondary Impacts*

Impacts to the individual physical and biological considerations above would be expected to be minor. Cumulatively, these impacts are expected to be minor. Further, secondary impacts would be expected to be minor.

8. *The following summarizes the potential economic and social effects of the proposed project on the human environment for the thermal combustor project. The "no action alternative" was discussed previously.*

SUMMARY OF COMMENTS ON POTENTIAL ECONOMIC AND SOCIAL EFFECTS:

The following comments have been prepared by the Department:

A. *Social Structures and Mores*

The permitting action would not be expected to cause a disruption to any native or traditional lifestyles or communities (social structures or mores) in the area. The nature of the site will not be changed and any impacts to social structures and mores would be expected to be minor.

B. *Cultural Uniqueness and Diversity*

The permitting action would not be expected to cause a change in the cultural uniqueness and diversity of the area because the land is currently used as a petroleum refinery and land use would not be changing. The nature of the site will not be changed. No impacts to cultural uniqueness and diversity would be expected.

C. *Local and State Tax Base and Tax Revenue*

A significant number of contract personnel would be required over the life of the construction project. However, no large-scale impacts to the local and state tax base and tax revenue would be expected beyond the construction completion.

D. *Agricultural or Industrial Production*

The permitting action would not result in a reduction of available acreage of any agricultural land outside of the refinery site. Changes in emissions of air pollutants would not be expected to impact agricultural productivity. No impacts to industrial production would be expected other than the direct increase in refinery capacity, and secondary increases with expanded refinery capacity.

E. *Human Health*

As described in Section 7.F and 7.H of this environmental assessment, impacts on air quality, water quality, and energy demands are expected to be minor. Further, the permit would have conditions and limitations derived from rules intended to protect public health. No more than minor impacts to human health would be expected as a result of this permitting action.

F. *Access to and Quality of Recreational and Wilderness Activities*

This permitting action would not be expected to have an impact on recreational or wilderness activities because the site is removed from recreational and wilderness areas or access routes. The action would not result in any changes in access to and quality of recreational and wilderness activities. Any impacts to recreational and wilderness activities would be expected to be minor.

G. *Quantity and Distribution of Employment*

A minor increase to the number of employees at the facility or in support of the facility is expected as a result of this permitting action. Any impacts to the quantity and distribution of employment would be expected to be minor.

H. *Distribution of Population*

A significant number of contract personnel would be required over the life of the construction project and may have some impact on population distribution during the duration of the project. Once the project is completed, the impact would be less.

I. *Demands of Government Services*

The demands on government services are not expected to increase with this permitting action. No additional permits are expected to be required.

J. *Industrial and Commercial Activity*

The resulting increase in crude production may result in some increase in industrial and commercial activity.

K. *Locally Adopted Environmental Plans and Goals*

CHS would be required to continue to comply with the State Implementation Plan and Federal Implementation Plan and associated stipulations for the Billings/Laurel area. The Department is not aware of any locally adopted environmental plans and goals which this project would interfere with.

L. *Cumulative and Secondary Impacts*

The impacts to the individual social and economic considerations above would be expected to be minor. From a cumulative viewpoint, and in consideration of secondary impacts, impacts would be expected to be minor.

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 this permitting action would be minor; therefore, an EIS is not required. In addition, the source would be applying BACT and the analysis indicates compliance with all applicable air quality rules and regulations.

Other groups or agencies contacted, or which may have overlapping jurisdiction: None.

Individuals or groups contributing to this EA: Department of Environmental Quality, Air, Energy & Mining Division - Air Quality Bureau.

EA Prepared By: Craig Henrikson

Date: 5/3/2020