



Montana Department of
ENVIRONMENTAL QUALITY

Brian Schweitzer, Governor

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December 30, 2010

Patrick B. Kimmet
Refinery Manager
CHS Inc.
P.O. Box 909
Laurel, MT 59044

Dear Mr. Kimmet:

The Department of Environmental Quality (Department) has made its decision on the Montana Air Quality Permit application for CHS, Inc (Laurel Refinery). The application was given permit number 1821-23. The Department's decision may be appealed to the Board of Environmental Review (Board). A request for hearing must be filed by January 31, 2011; however, this permit shall become final on January 15, 2011, unless the Board orders a stay on the permit.

Procedures for Appeal: Any person jointly or severally adversely affected by the final action may request a hearing before the Board. Any appeal must be filed before the final date stated above. The request for a hearing shall contain an affidavit setting forth the grounds for the request. Any hearing will be held under the provisions of the Montana Administrative Procedures Act. Submit requests for a hearing in triplicate to: Chairman, Board of Environmental Review, P.O. Box 200901, Helena, Montana 59620.

For the Department,

Vickie Walsh
Air Permitting Program Supervisor
Air Resources Management Bureau
(406) 444-9741

Skye Hatten, P.E.
Environmental Engineer
Air Resources Management Bureau
(406) 444-5287

VW: SH
Enclosures

Montana Air Quality Permit

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

MAQP: #1821-23
Application Complete: 11/1/2010
Preliminary Determination Issued: 12/10/2010
Department Decision Issued: 12/30/2010
Permit Final: 01/15/2011
AFS #: 111-0012

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to CHS Inc. (CHS) pursuant to Sections 75-2-204, 211, 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 following permitted equipment, by section:

- Section II. Plant-Wide Requirements (including Plant-wide Applicability Limits (PALs)). The refinery flare is not included under the PAL.
- Section III. Fuel Gas & Fuel Oil Combustion Devices
- Section IV. Hydrodesulfurization (HDS) complex with associated Zone D sulfur recovery unit (SRU) and tail gas treatment unit (TGTU)
- Section V. Boiler #10
- Section VI. Truck Loading Rack and Vapor Combustion Unit (VCU)
- Section VII. No. 1 Crude Unit
- Section VIII. Ultra Low Sulfur Diesel (ULSD) Unit and Hydrogen Plant
- Section IX. TGTU for Zone A's SRU #1 and SRU #2 trains
- Section X. Fluidized Catalytic Cracking Unit (FCCU)
- Section XI. Naphtha Hydrotreater (NHT) Unit, Delayed Coker Unit, and Zone E SRU/TGTU and Tail Gas Incinerator (TGI)
- Section XII. Boiler #11
- Section XIII. Railcar Light Product Loading Rack and VCU
- Section XIV. Boiler #12
- Section XV. Benzene Reduction Unit

B. Current Permit Action

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

In this application, CHS proposes to convert the existing HDS Unit into a Mild Hydrocracker. Capacities of the existing 100 Unit Hydrogen Plant and the SRU/TGTU will be increased, the existing feed heater in the FCC Unit will be replaced and a rate-limiting pressure safety valve (PSV) in the NHT will be 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 will be to produce an increased volume of higher quality diesel fuel.

The application also includes information related to an additional project that will be completed at the refinery concurrent with the Mild Hydrocracker Project. 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.

Section II: Plant-wide Refinery Limitations and Conditions (the refinery flare is not included).

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 Plant-wide Emission Limitations (ARM 17.8.749):

1. Sulfur dioxide (SO₂) emissions shall not exceed 2,980.3 tons per year (TPY)
2. Nitrogen Oxide (NO_x) emissions shall not exceed 999.4 TPY
3. Carbon Monoxide (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 Continuous Emission Monitoring System (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 (Plant-Wide Refinery Limitations and Conditions Compliance Determination).

D. Reporting and Recordkeeping Requirements (ARM 17.8.749):

CHS shall provide quarterly 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 (both the Billings regional and the Helena offices) 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 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 and Fuel Oil 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 as applicable, with the exception of the existing refinery flare. The flare will be subject to Subpart J once EPA has approved all proposed Alternative Monitoring Plans (CHS Consent Decree Paragraphs 55 and 57).
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 and Fuel Oil Combustion Devices

1. SO₂ emissions from the combustion of alkylation unit polymer is limited to 50 tons per rolling 365-day time period (ARM 17.8.749). Periods of natural gas curtailment are not exempt from this limit.
2. Fuel oil combustion in refinery boilers is prohibited (ARM 17.8.749).
3. For fuel gas and fuel oil 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 ppm_{v,d} H₂S) per rolling 3-hour average (ARM 17.8.340, ARM 17.8.749, 40 CFR 60, Subpart J).
4. Refinery fuel gas burned in fuel combustion devices shall not exceed 0.05 grains of H₂S per dry standard cubic foot (81 ppm_{v,d} H₂S) per 12-month average (ARM 17.8.340 and ARM 17.8.749).

5. The burning of old sour water stripper overhead (SWSOH) in any fuel gas combustion device is prohibited (CHS Consent Decree Paragraphs 43 and 50 and Appendix A).
6. By December 31, 2011, CHS shall cease operation of Boilers #4 and #5 (CHS Consent Decree).
7. 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 ppmv determined hourly on a 3-hour rolling average basis and H₂S in excess of 60 ppmv determined daily on a 365-successive calendar day rolling average basis (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Ja).

D. Monitoring Requirements

1. CHS shall install and operate the following CEMS/Continuous emission rate monitors (CERMS): Continuous concentration (dry basis) monitoring of H₂S in refinery fuel gas burned in all refinery fuel gas combustion devices, with the exception of refinery fuel gas streams with approved Alternative Monitoring Plans (AMP) or AMPs under review.
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, Subparts 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 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. Fuel oil metering and analysis specifications (SOP SIP Method C-1) 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. 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.

2. Compliance determinations for the SO₂ limit from the combustion of alkylation unit polymer and fuel oil in all combustion devices shall be based upon methodology required in the Billings-Laurel SO₂ SIP and Appendix G of the CHS Consent Decree.
3. In addition to the testing required in each section, compliance determinations for the emission limits applicable to the fuel gas and fuel oil combustion devices 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).
4. CHS shall provide the Department (both the Billings regional office and the Helena office) with written notification of the shutdown date(s) of Boilers #4 and #5 within 15 days after the actual shutdown date(s) (ARM 17.8.749).

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

CHS shall submit quarterly emission reports to the Department. Emission reporting for SO₂ generated from the combustion of fuel oil and alkylation unit polymer shall consist of a daily 365-day rolling average (tons/year) for each calendar day. CHS shall submit the quarterly emission reports within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department.

The quarterly report shall also include the following:

1. Source or unit operating time during the reporting period (Alkylation Unit and boilers burning fuel oil) 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.
6. For those refinery fuel gas streams covered by AMPs, the report should identify instances where AMP conditions were not met.

Section IV: Limitations and Conditions for the HDS Complex (future 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 SRU Incinerator Stack (E-407 & INC-401), 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).
 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 the HDS unit.
 5. 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 Mild Hydrocracker unit once constructed.
 6. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the HDS unit.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants (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 ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. This applies to the replacement C-201B Compressor installed in 2006.¹
- 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 HDS complex (ARM 17.8.304 (2)).
- D. Limitations on Individual Sources
1. Zone D SRU Incinerator Stack (INC-401)
 - a. SO₂ emissions from the Zone D SRU incinerator stack shall not exceed

¹ 40 CFR 63, Subpart ZZZZ will no longer be applicable after completion of the Mild Hydrocracker Project because the gas driven motor on the C-201B compressor will be converted to an electric driven motor.

(ARM 17.8.749):

- i. 31.1 tons/rolling 12-calendar month total,
 - ii. 125 ppm_{vd}, rolling 12-month average corrected to 0% oxygen, on a dry basis,
 - iii. 341.04 lb/day,
 - iv. 14.21 lb/hr, and
 - v. 250 parts per million, volumetric dry (ppm_{vd}), rolling 12-hour average corrected to 0% oxygen, on a dry basis.
- b. 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) to no more than 125 ppm_{vd} on a rolling 12-month average corrected to 0% oxygen on a dry basis (ARM 17.8.752).
- c. 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.
- d. CHS shall not fire fuel oil in this unit (ARM 17.8.749).

2. Compressor Gas Engine Stack (C-201B)

As included in MAQP #1821-23, the gas driven motor on the existing hydrogen compressor C-201B will be replaced with an electric driven motor. Once the replacement occurs, the following conditions will no longer be applicable.

- a. NO_x emissions from C-201B shall not exceed (ARM 17.8.749):
- i. 30.43 tons/rolling 12-calendar month total
 - ii. 7.14 lb/hr
- b. CO emissions from C-201B shall not exceed (ARM 17.8.749):
- i. 68.59 tons/rolling 12-calendar month total
 - ii. 6.40 lb/hr when firing natural gas
 - iii. 16.10 lb/hr when firing propane
- c. VOC emissions from C-201B shall not exceed 10.1 tons/rolling 12-calendar month total (ARM 17.8.749).
- d. CHS shall only combust natural gas or propane in C-201B (ARM 17.8.749).
- e. CHS will maintain and operate a CO catalyst on the C-201B compressor exhaust (ARM 17.8.749).

3. 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).

4. 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 24-hour rolling average basis (40 CFR 60, Subpart Ja)
 - ii. 2.6 lb/hr (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. During periods of startup or shutdown, CO emissions from the H-102 Reformer Heater shall not exceed 11.5 lb/hr on a 24-hour rolling average (ARM 17.8.749).
- f. H-102 shall be fitted with ULNBs (ARM 17.8.752).
- g. CHS shall implement proper design and good combustion techniques to

minimize CO, VOC, and PM/PM₁₀/PM_{2.5} emissions (ARM 17.8.752).

5. 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).

6. 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 (E-407/INC-401):
 - a. SO₂ (SO₂ SIP, 40 CFR 60 Subparts J and Ja)
 - b. O₂ (40 CFR 60, Subparts J and Ja)
 - c. Volumetric Flow Rate (SO₂ SIP)

2. CHS shall conduct biennial performance tests for the Reformer Heater Stack (H-102) in accordance with 40 CFR 60, Subpart Ja (ARM 17.8.749, 40 CFR 60, Subpart Ja).
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, breakdowns, and repairs. Startup shall be considered to be when acid gas and SWS streams are first introduced into the sulfur recovery facility. 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. With exception to the initial performance test period, compliance with IV.D.4.c and d 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 Reformer Heater (H-102). 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).

F. Testing Requirements

1. The SRU Incinerator Stack (E-407 & INC-401) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for SO₂ and NO_x, and the results submitted to the Department in order to demonstrate compliance with the SO₂ and NO_x emission limits contained in Section IV.D.1.a, b and c (ARM 17.8.105 and ARM 17.8.749).
2. The Superior Clean Burn II 12 SGIB (C201-B) compressor engine shall be tested annually, 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.D.2.a and b (ARM 17.8.105 and ARM 17.8.749).
3. The Reformer Heater Stack (H-101) shall be tested annually, 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.D.3.b and c (ARM 17.8.105 and ARM 17.8.749).
4. The Reformer Heater Stack (H-102) shall be tested annually, 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.D.4.c and d (ARM 17.8.105 and ARM 17.8.749).

5. The Reactor Charge Heater Stack (H-201) shall be tested every two 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 Section IV.D.5.b and c (ARM 17.8.105 and ARM 17.8.749).
6. The Fractionator Feed Heater Stack (H-202) shall be tested every two 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 Section IV.D.6.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.F, 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.E.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 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. CHS shall submit the monthly emission reports within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. 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.D.1 through 6.
4. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Sections IV.D.1 through 6 (ARM 17.8.749).
5. Reasons for any emissions in excess of those specifically allowed in Sections IV.D.1 through 6 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.
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, CO, and VOC concurrently at a minimum of every 5 years or according to another testing/monitoring schedule as may be approved 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 emission reports to the Department within 30 days of the end of each calendar quarter. Copies of the quarterly emission reports, excess emissions, emission testing reports and other reports required by Sections V.D and V.F.1 shall be submitted to both the Billings regional office and the Helena office. 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 (this requirement applicable upon startup of Boiler #10 following installation of the ULNBs)
 - v. Daily average and maximum lb/hr (this requirement applicable upon startup of Boiler #10 following installation of the ULNBs)
 - 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.

G. Notification

CHS shall provide the Department (both the Billings regional office and the Helena office) with written notification of the actual installation of the ULNBs on Boiler #10 within 15 days after the actual installation date (ARM 17.8.340 and ARM 17.8.749).

Section VI: Limitations and Conditions for the Truck Loading Rack Vapor Combustion Unit (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 - NESHAP from Petroleum Refineries shall apply to, but not be limited to, the truck ("product") loading rack and VCU.
 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).
 - 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 VCU stack shall be 35 feet above grade (ARM 17.8.749).

B. Emission Limitations for the Truck 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 enclosed VCU any visible emissions that exhibit an opacity of 20% or greater over any 6 consecutive minutes (ARM 17.8.304(2)).

C. 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 continuously operate a thermocouple and an associated recorder, or an ultraviolet flame detector and relay system, which will render the loading rack inoperable if a flame is not present at the VCU, or any other equivalent device, to detect the presence of a flame (ARM 17.8.342 and ARM 17.8.752).
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 60.482-1 through 60.482-10.

D. 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.B.1 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 and 3, as required by the Department (ARM 17.8.105).

E. 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 63.654.

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 GGG - Standards of Performance for Equipment Leaks of VOC in the Petroleum Refineries applies to the various new pumps, valves, flanges, and other equipment in Hazardous Air Pollutant (HAP) service within the No. 1 Crude Unit (40 CFR 63, Subpart CC: Maximum Achievable Control Technology (MACT) Standards for Petroleum Refineries).

B. 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.

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 new ULSD Unit heaters (H-901 and H-902) and the Hydrogen Plant heater (H-1001).
3. 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.
4. 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. 2.19 tons/rolling 12-calendar month total
 - ii. 0.50 lb/hr
 - c. CO emissions from H-901 shall not exceed (ARM 17.8.752):
 - i. 9.00 tons/rolling 12-calendar month total
 - ii. 2.05 lb/hr
 - d. VOC Emissions from H-901 shall not exceed 0.59 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. 4.40 tons/rolling 12-calendar month total
 - ii. 1.00 lb/hr
 - c. CO emissions from H-902 shall not exceed (ARM 17.8.752):
 - i. 8.50 tons/rolling 12-calendar month total
 - ii. 1.94 lb/hr
 - d. VOC Emissions from H-902 shall not exceed 1.19 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. SO₂ emissions from H-1001 shall not exceed (ARM 17.8.752):
 - i. 12.69 tons/rolling 12-calendar month total
 - ii. 5.80 lb/hr
- b. NO_x emissions from H-1001 shall not exceed (ARM 17.8.752):
 - i. 28.31 tons/rolling 12-calendar month total
 - ii. 6.46 lb/hr
- c. CO emissions from H-1001 shall not exceed (ARM 17.8.752):
 - i. 400 ppmvd at 3% oxygen on a 30-day rolling average
 - ii. 14.15 tons/rolling 12-calendar month total
 - iii. 3.23 lb/hr
- d. VOC Emissions from H-1001 shall not exceed 3.82 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).

E. Monitoring Requirements (ARM 17.8.340).

- 1. CHS shall install and operate the following (CEMS/CERMS) for H-1001:
 - a. O₂ (40 CFR 60, Subpart J)
 - b. SO₂ (40 CFR 60, Subpart J)
- 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 J, 60.100-108, and Appendix B, Performance Specifications 2, 3, 4 or 4A, and Appendix F. The volumetric flow rate monitor shall, if required, 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.

F. Testing Requirements

- 1. The Reactor Charge Heater (H-901) shall be tested every two 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 Section VIII.D.1.b and c (ARM 17.8.105 and ARM 17.8.749).

2. The Fractionator Reboiler (H-902) shall be tested every two 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 Section VIII. D.2.b and c (ARM 17.8.105 and ARM 17.8.749).
3. The Reformer Heater (H-1001) shall be tested annually, 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 VIII.D.3.b and c (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 SO₂ limit in Section VIII.D.3 for 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)

CHS shall prepare and submit a quarterly emission report within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The quarterly report shall also include the following:

1. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates and SO₂ in the H-1001 stack.
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 VIII.D.1 through 3.
4. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in VIII.D.1 through 3.
5. Reasons for any emissions in excess of those specifically allowed in VIII. D.1 through 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 (Consent Decree paragraph 63 and ARM 17.8.749)
 - b. 200 ppm, rolling 12-month average corrected to 0% oxygen, on a dry basis
 - c. 40.66 tons/rolling 12-month total
 - d. 11.60 lb/hr
 - e. 278.40 lb/day
 2. CHS shall operate and maintain the TGTU on the Zone A SRU to limit SO₂ emissions from the Zone A SRU-AUX-4 stack to no more than 200 ppm on a rolling 12-month average corrected to 0% oxygen on a dry basis.
 3. 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
4. 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 (CHS Inc, Consent Decree):
 - 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 annually, or according to another testing/monitoring schedule as may be approved by the Department for SO₂, and shall be tested on an every 5-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. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department.

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, PM and opacity.
 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 new FCCU Charge Heater (FCC-Heater-NEW) is subject to the fuel gas combustion device 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. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed on or before November 23, 1968, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

D. Limitations on Individual Emitting Units

1. FCCU Regenerator Stack

- a. CO emissions from the FCCU Regenerator Stack shall not exceed 500 ppm at 0% O₂ per 1-hour time period (CHS Consent Decree Paragraph 41, ARM 17.8.340, 40 CFR Part 60, Subpart J; 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 (CHS Consent Decree Paragraph 41).
- 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 (CHS Consent Decree Paragraphs 32-33).
- 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 17.8.752).
- 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 (CHS Consent Decree Paragraph 29 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, malfunction or hydrotreater outages, 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 (CHS Consent Decree Paragraph 29 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).

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

As included in MAQP #1821-23, FCC-Heater-NEW will be installed to replace FCC-Heater-1. FCC-Heater-1 shall be shutdown and removed as an emissions source within 190 days of the initial startup of FCC-Heater-NEW. The following conditions shall apply once FCC-Heater-NEW begins operation.

- a. The FCC Charge Heater (FCC-Heater-1) shall not exceed 49.7 MMBtu/hr on a rolling 12-calendar month basis (ARM 17.8.749).
- b. NO_x emissions from the FCC Charge Heater (FCC-Heater-1) shall not exceed (ARM 17.8.749):
 - i. 22.87 tons/rolling 12-calendar month total

- ii. 6.27 lb/hr
- c. CO emissions from the FCC Charge Heater (FCC-Heater-1) shall not exceed (ARM 17.8.749):
 - i. 19.21 tons/rolling 12-calendar month total
 - ii. 5.26 lb/hr

2a. FCC Charge Heater (FCC-Heater-NEW)

As included in MAQP #1821-23, FCC-Heater-NEW will be installed to replace FCC-Heater-1. FCC-Heater-1 shall be shutdown and removed as an emissions source prior to startup of FCC-Heater-NEW. The following conditions shall apply once FCC-Heater-NEW begins operation.

- a. NOx emissions from H-102 shall not exceed:
 - i. 40 ppmv (dry basis, corrected to 0 percent excess air) on a 24-hour rolling average basis (40 CFR 60, Subpart Ja)
 - ii. 2.1 lb/hr (ARM 17.8.752)
 - iii. 9.2 tons/rolling 12-calendar month total (ARM 17.8.749)
- b. CO emissions from H-102 shall not exceed:
 - i. 4.0 lb/hr (ARM 17.8.752)
 - ii. 17.5 tons/rolling 12-calendar month total (ARM 17.8.749)
- c. During periods of startup and shutdown, CO emissions from the new FCC Charge Heater (FCC-Heater-NEW) shall not exceed 8.0 lb/hr on a 24-hour rolling average (ARM 17.8.749).
- d. FCC-Heater-NEW shall be fitted with ULNBs (ARM 17.8.752).
- e. CHS shall not burn in the FCC Charge Heater (FCC-Heater-NEW) 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).
- 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).

E. Monitoring Requirements

- 1. CHS shall install and operate the following CEMS/CERMS on the FCCU Regenerator Stack (CHS Consent Decree):
 - a. CO
 - b. NO_x
 - c. SO₂
 - d. O₂
 - e. Opacity (40 CFR 63, Subpart UUU)
- 2. CHS shall conduct biennial performance tests for the FCC Charge Heater (FCC-Heater-NEW) in accordance with 40 CFR 60, Subpart Ja (ARM 17.8.749, 40 CFR 60, Subpart Ja).

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 shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1.
4. The FCCU 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. 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 on an annual basis or on another testing schedule as may be approved by the Department (CHS Consent Decree Paragraph 38 and ARM 17.8.105).
2. The FCC Charge Heater (FCC-Heater-1) shall be tested annually, 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 X.D.2.b and c (ARM 17.8.105 and ARM 17.8.749).
3. The FCC Charge Heater (FCC-Heater-NEW) shall be tested annually, 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 emission limit contained in Section X.D.2a.a (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 with the opacity limitation 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)

CHS shall submit quarterly emission reports to the Department based on data from the installed CEMS/CERMS. Emission reporting for CO from the emission monitor shall consist of a daily maximum 1-hour average (ppm) for each calendar day. CHS shall

submit the quarterly emission reports within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. 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.
5. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section X.D (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 Naptha Hydrotreating Unit, Delayed Coker Unit 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 GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the Naptha Hydrotreating Unit and the Delayed Coker Unit fugitive piping equipment in VOC service.
 4. 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. VOC Emissions from the Coker Charge Heater (H-7501) shall not exceed 1.41 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).
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 Part 63.11 (40 CFR 63.11, 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 (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).
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. While operating the delayed coking unit, CHS shall depressurize to 5 lb per square inch gauge (psig) during reactor vessel depressurizing and vent the exhaust gases to the fuel gas recovery system for combustion in a fuel gas combustion device. The vessel shall not be opened to atmosphere until the pressure is 5.0 psig or lower. (ARM 17.8.749).
 - b. VOC emissions from the Coke Drum Steam Vent shall not exceed 18.10 tons/yr as determined on a monthly rolling 12-month average (ARM 17.8.749).
 - c. PM₁₀ emissions from the Coke Drum Steam Vent shall not exceed 4.52 tons/yr as determined on a monthly rolling 12-month average (ARM 17.8.749).

E. Monitoring requirements

- 1. CHS shall install and operate the following (CEMS/CERMS):

Zone E SRU/TGTU/TGI (Billings/Laurel SO₂ SIP)

- i. SO₂ (40 CFR 60, Subpart J)
 - ii. O₂ (40 CFR 60, Subpart J)
 - iii. Volumetric Flow Rate (Billings/Laurel SO₂ SIP)
- 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 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

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.
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.
5. CHS shall continuously monitor the pressure in the coke drums such that the pressure at which each drum is depressurized can be determined (ARM 17.8.749).

F. Testing Requirements

1. The NHT Charge Heater (H-8301) shall be tested every two 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 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 annually, 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 annually, or according to another testing/monitoring schedule as may be approved by the Department for SO₂, and shall be tested on an every 5-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 = pressure (psig) at which each coke drum is depressurized.

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. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The quarterly report shall also include the following:
 - 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 (ARM 17.8.749).
2. For non-minor (defined in the June 12, 1998 Stipulation) flaring events, CHS shall comply with the reporting requirements identified in Section (3)(A)(5) of Exhibit A-1 of the Stipulation signed by the Board of Environmental Review on June 12, 1998 (ARM 17.8.749).
3. CHS shall include in the quarterly emissions report the VOC and PM₁₀ emissions as tons/rolling 12-month total and any instances that the drum is not depressurized at below 5 psig (ARM 17.8.749).

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.
- 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. 18.3 tons/rolling 12-calendar month total
 - b. 4.18 lb/hr
 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, Subparts J, 60.100-108, 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. 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 #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).
5. 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 annually, 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.

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. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. 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)

- A. CHS shall commence construction of the expansion of the Railcar Light Product Loading Rack no later than June 27, 2011 (three years following issuance of MAQP #1821-17) or the construction permit for such expansion shall expire (ARM 17.8.749 and ARM 17.8.762).
- B. 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 R – Gasoline Distribution MACT
 3. 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.
- C. 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).
- 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 R).
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, and compliance demonstrated with the emission limitation contained in Section XIII.C.1 within 180 days of initial startup and testing continued every 5 years, or according to another testing/monitoring schedule as may be approved by the Department, until such time that the expansion of the Railcar Light Product Loading Rack is complete. Following construction completion of the Railcar Light Product Loading Rack expansion, the VCU shall be tested on an every 2-year basis. 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 initially 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 within 180 days of initial start up (ARM 17.8.105).

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.
 4. Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries 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, rolling 12-month 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):
 - a. 0.02 lbs/MMBtu-HHV, on a rolling 365-calendar day average
 - b. 18.31 tons/rolling 12-calendar month total
 - c. 4.18 lb/hr
 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 J, 60.100-108, 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 annually, 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. In addition to stack testing required in Section XIV.E, compliance determinations for the NO_x limits in Section XIV.C for Boiler #12 shall also be based upon monitoring data as required in Section XIV.D.
2. 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.
3. 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. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. 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

7. 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

- 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.

 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 initially tested 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. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. 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 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/hr per calendar day
 - b. Total tons per month
3. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates.
4. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section XV.D.1 through 5.
5. 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.

H. Notification Requirements

CHS shall provide the Department (both the Billings regional office and the Helena office) with written notification of the actual start-up date of the Platformer Splitter Reboiler within 15 days after the actual start-up date (ARM 17.8.340 and ARM 17.8.749).

Section XVII: 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 (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.
- B. Waiver - The permit and all the terms, conditions, and matters stated herein shall be deemed accepted if 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

Plant-Wide Refinery Limitations and Conditions 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. Fuel oil fired external combustion
 - 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, ULSD Unit (900 Unit), Hydrogen Plant (1000 Unit), Delayed Coker

Unit combustion sources, Boiler #11, and NHT Charge Heater (H-8301)

- 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. Boilers #10 and #12
- 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 J, 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. Zone E 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 5ve-year stack tests
 - ii. Key Parameters: Every 5-year NO_x stack test, monthly fuel use (scf)
 - c. CO, PM₁₀/PM, VOC: Not applicable – not a significant source
11. 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)
12. 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)

13. 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.)

14. Storage tanks

- a. SO₂, NO_x, CO, PM₁₀/PM: Not applicable – not a source
- b. VOC
 - i. Calculation Basis: EPA TANKS4.0
 - 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 #1821-23

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, with the exception of the source categories for the Plant-wide Applicability Limit (PAL), which are listed below.

1. Gas-fired external combustion source type, includes:

- #1 crude heater, crude preheater, #1 crude vacuum heater
- #2 crude heater, #2 crude vacuum heater
- Alkylation Unit hot oil belt heater
- Platformer Heater (P-HTR-1), platformer debutanizer heater
- Fluid Catalytic Cracking (FCC) Charge Heater (FCC-Heater-1)
- Naphtha Hydrotreater (NHT) Charge Heater (H-8301), NHT Reboiler Heater #1 (H-8302), NHT Reboiler Heater #2 (H-8303), and NHT Splitter Reboiler (H-8304)
- Zone D Hydrogen Plant Reformer Heater (H-101), Reformer Heater in the 100 Unit Hydrogen Plant (H-102), Reactor Charge Heater (H-201), Fractionator Feed Heater (H-202)
- Ultra Low Sulfur Diesel (ULSD) Unit Reactor charge heater (H-901), ULSD Unit Fractionation heater (H-902)
- Hydrogen Plant Reformer heater (H-1001)
- Coker Charge Heater (H-7501)
- Asphalt Loading Heater #1
- #1 fuel oil heater, #60 tank heater
- Boiler #5, Boiler #9, Boiler #10, Boiler #11, and Boiler #12
- Platformer Splitter Reboiler (P-HTR-3)
- New FCC Charge Heater (FCC-Heater-NEW)

2. Fuel oil-fired external combustion sources, includes: #4 boiler, and #5 boiler (until startup of Boiler #12);

3. Gas-fired internal combustion source, includes: Platformer recycle turbine;
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 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 source type includes: old American Petroleum Institute (API) separator, Zone D API separator, ULSD Unit Wastewater, TGTU Wastewater; Benzene Reduction Unit Oily Water Sewer
10. Cooling tower sources: #1 cooling tower (CT), #2 CT, #3 CT, #5 CT, and #6 CT;
11. Loading facilities: light product truck rack and vapor combustion unit (VCU), heavy oil truck rack, heavy oil rail rack; and railcar light loading rack and VCU; and
12. Storage tanks: tank numbers 2, 7, 12, 41, 47, 56, 60, 61, 62, 63, 65, 66, 67, 68, 70, 71, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 85, 86, 87, 88, 91, 92, 93, 94, 95, 96, 97, 98, 99, 100, 101, 102, 103, 104, 105, 106, 107, 108, 109, 110, 111, 112, 113, 114, 115, 116, 117, 118, 119, 120, 121, 122, 123, 126, 127, 128, 129, B-1, B-2, B-7, firetk 2, firetk 3, firetk 4, TGTU-VSSL-6, and coker sludge storage tank (TK-7504).

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	3.5 ton/yr
		11.52 lb/day 0.48 lb/hr	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
VOC	6.26 ton/yr	10.1 ton/yr	
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	
Reactor Charge Heater (H-201)	SO ₂	0.214 lb/hr	1.716 lb/hr
		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
	SO ₂	304.2 ton/yr	290.9 ton/yr

Source	Pollutant	Previous Limit	New Limit
Old Sour Water Stripper	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. Napthalene
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 TPY + 40 TPY – 0.1 TPY = 2980.3 TPY = 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 Unifiner 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:

Constituent	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 under the current permit action, 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 “*Naptha 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 naptha 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 shutdown in part to meet the consent decree NO_x reduction requirements, as well as to generate NO_x offsets for this permitting action.² 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.

2. 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).

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. 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 super-heated 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.³

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 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

3. 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.

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 two 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.

C. Current Permit Action

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 proposes to convert the existing HDS Unit into a Mild Hydrocracker. Capacities of the existing 100 Unit Hydrogen Plant and the Zone D SRU/TGTU will be increased, the existing feed heater in the FCC Unit will be replaced and a rate-limiting pressure safety valve (PSV) in the NHT will be 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 will be 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 will be made:

- 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 will be made:

- 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 will be made:

- 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 will be made:

- 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.

“ULSD Burner Fuel Project”

The application also includes information related to an additional project that will 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 replaces MAQP #1821-22.

D. Response to Public Comments

Person/Group Commenting	Permit Reference	Comment	Department Response
CHS	Section I.B	CHS suggests removal of the statement "...by utilizing more hydrogen to convert gasoil into diesel" in order to provide clarification.	The Department has made the change as suggested.
CHS	Section I.B	CHS requests replacement of "...project discussed above" with "Mild Hydrocracker project."	The Department has made the change as requested.

CHS	Section III	In summary, CHS noted several instances that permit conditions are repeated, which may lead to an unintended result should an exceedance occur.	The Department takes note of this concern.
CHS	III.A.	CHS notes that the Subpart Ja requirement should be numbered III.A.3.	The Department has updated this requirement.
CHS	III.C.3.	The correct conversion from 0.10 grains of H ₂ S per dry standard cubic foot is 162 ppmvd H ₂ S rather than 161 ppmvd H ₂ S. The difference between the two is a matter of rounding.	The Department has modified this condition to reflect the correct value.
CHS	III.C.3.	CHS suggests separation of the two limitations listed under this condition for clarification.	The Department separated these limitations into separate conditions.
CHS	III.C.6	CHS requests changing the units of the NSPS Ja limit from ppmvd to ppmv.	The Department has modified this condition as requested.
CHS	IV	CHS suggests the name of this section to be updated to "HDS Complex (future Mild Hydrocracker)."	The Department has modified this heading as requested.
CHS	IV.A.2. and 3.	The "s" at the end of "Hydrogen Reformer Heaters" should be removed.	The Department has made the change as requested.
CHS	IV.A.4..	CHS suggests adding NSPS Subpart GGGa applicability to this section.	The Department has made the change as requested.
CHS	IV.B.2.	CHS suggests a comment noting that the C-201B compressor will no longer be subject to 40 CFR 63 Subpart ZZZZ provisions once the motor is converted to an electric driven motor.	The Department has included the comment as suggested.
CHS	IV.D.1.	For the Zone D SRU Incinerator Stack limits, CHS suggests that the current permit limits be re-added and maintained in the permit until the project has been completed.	The Department has included the permit limits as suggested.
CHS	IV.D.1.	Following completion of the expansion of the Zone D SRU/TGTU, the E-407 combustion source will be eliminated. As such, its reference can be removed from the section heading and the IV.D.1.b. condition.	The Department has removed reference to E-407 in the applicable sections.
CHS	IV.D.2.	CHS suggests removal of the statement "C-201B is slated to be replaced with an electric driven make up hydrogen compressor" and replacement with "the gas driven motor on existing hydrogen compressor C-201B will be replaced with an electric driven motor."	The Department has made the change as suggested.
CHS	IV.D.4.a.	CHS suggests the following change: "All available 100 Unit PSA tailgas shall be fired in the H-102 Reformer Heater 100 Unit Hydrogen Plant reformer heaters, except during periods of startup, shutdown or process upset."	The Department has made the change as suggested.
CHS	IV.D.4.b.	CHS recommends removal of this permit condition as it is repetitive.	The Department has made the change as suggested.
CHS	IV.D.4.c.	CHS proposes the following alternate language to this permit condition:	The Department has made the change as proposed.

		"CHS shall not burn in the H-102 Reformer Heater any fuel gas that contains H ₂ S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis."	
CHS	IV.D.4.d.	CHS notes that process heaters with a rated heating capacity of less than 100 MMBTU/hr that also have low or ultra low NO _x burners is not subject to continuous monitoring requirements. Because the limits originally proposed create difficulty in demonstrating compliance without a continuous monitoring system, the following NO _x limits are proposed: a. 40 ppmv (dry basis, corrected to 0% excess air) on a 24-hour rolling average basis. b. 2.6 lb/hr c. 11.3 tons/ rolling 12-calendar month total	The Department has modified the NO _x limits as proposed.
CHS	IV.D.4.f.	CHS requests the following CO emissions conditions be added for the purpose of demonstrating compliance with the proposed BACT: a. 5.7 lb/hr b. 25.1 tons/rolling 12-calendar month total	The Department has included the CO emissions conditions as proposed.
CHS	IV.D.4.	CHS proposes the following condition for CO emissions during startup and shutdown: "During periods of startup or shutdown, CO emissions from the H-102 Reformer Heater shall not exceed 11.5 lb/hr on a 24-hour rolling average.	The Department has included the CO emissions during startup and shutdown as proposed.
CHS	IV.E.2.a.	An exemption from continuous H ₂ S monitoring of PSA tailgas is included as part of NSPS Ja because it is a fuel gas stream intolerant to sulfur contamination. Also, all refinery fuel gas combusted in fuel gas combustion devices in the refinery is monitored by existing H ₂ S CEMs. CHS request removal of the requirement for CEMs monitoring of SO ₂ .	The Department has removed the requirement as requested.
CHS	IV.E.2.b. and c.	The new Reformer Heater H-102 has a heating capacity less than 100 MMBTU/hr, of which NSPS Subpart Ja requires continuous monitoring. Instead, biennial performance tests are required.	The Department has made the change requested.
CHS	IV.F.4.	CHS suggests the following change: "...for NO _x and CO, concurrently , and the results..."	The Department has made the change requested.
CHS	X.A.3.	CHS suggests this condition be expanded to specifically identify which facilities in the FCCU are subject to NSPS Subpart Ja.	The Department has made the change requested.

CHS	X.D.1.d.-g.	CHS suggests "FCCU" be changed to "FCCU Regenerator Stack."	The Department has made the change requested.
CHS	X.D.2 and 2a.	CHS suggests alternate language to indicate a 180 day period of time for shutdown of FCC-Heater-1 following initial startup of FCC-Heater-NEW.	The Department has made the change requested.
CHS	X.D.2a.a. and X.F.3.	CHS notes that there may be operating scenarios (i.e. start of run conditions) in which the heater will operate below its normal heat release rate. This may lead to a situation in which it may not be physically possible from a process standpoint to increase the heater's firing rate to the level typically required for a performance test. CHS will advise the Montana DEQ if such a scenario is identified during the design phase of the new FCC heater.	The Department notes the comment.
CHS	X.D.2a.a.	CHS notes that because the limits originally proposed create difficulty in demonstrating compliance without a continuous monitoring system, the following NOx limits are proposed: a. 40 ppmv (dry basis, corrected to 0% excess air) on a 24-hour rolling average basis. b. 2.1 lb/hr c. 9.2 tons/ rolling 12-calendar month total	The Department has modified the NOx limits as proposed.
CHS	X.D.2a.c.	CHS proposes the following alternate language to this permit condition: "CHS shall not burn in the FCC Charge Heater (FCC-Heater-NEW) any fuel gas that contains H ₂ S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis."	The Department has made the change requested.
CHS	X.D.2a.d.	CHS requests the following CO emissions conditions be added for the purpose of demonstrating compliance with the proposed BACT: a. 4.0 lb/hr b. 17.5 tons/rolling 12-calendar month total	The Department has included the CO emissions conditions as proposed.
CHS	X.D.2a.d.	CHS proposes the following condition for CO emissions during startup and shutdown: "During periods of startup or shutdown, CO emissions from the new FCC Charge Heater (FCC-Heater-NEW) shall not exceed 8.0 lb/hr on a 24-hour rolling average."	The Department has included the CO emissions during startup and shutdown as proposed.
CHS	X.E.2.	The new Reformer Heater H-102 has a heating capacity less than 100 MMBTU/hr, of which NSPS Subpart Ja requires continuous monitoring. Instead, biennial performance tests are	The Department has made the change requested.

		required.	
CHS	X.F.3.	CHS suggests the following change: "...for NOx and CO, concurrently , and the results..."	The Department has made the change requested.
CHS	XVI.	CHS generally suggests moving the language included within this section to Section IV.A.	The Department has made the change requested.
CHS	P.A. I.A.1.	The new FCC Charge Heater (FCC-Heater-NEW) should be added to the gas-fired external combustion source type list.	The Department has made the change requested.
CHS	P.A. I.C. Current Permit Action	CHS suggests a rearrangement of the content of this section in order to provide clarification. Additionally, CHS suggests adding project details associated with the 100 Unit Hydrogen plant as part of the Mild Hydrocracker project.	The Department has made the change requested.
CHS	P.A. IV. Table 2	CHS requests updating this table to include emissions increase values for the Alkylation Hot Oil Heater.	The Department has made the change requested.

F. 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 - A new SWS was constructed, which replaced the operation of the older existing SWS. The new SWS unit serves the existing and proposed facilities of this HDS project. The old SWS cannot be removed, however, and functions only as the back-up unit. Sour water from a variety of sources in the refinery is accumulated in the sour water storage tank where hydrocarbons are separated. The hydrocarbon is sent to the existing slop oil system for recovery. The gas vapors from the sour water tank are compressed and sent to the tail gas unit for sulfur recovery. Sour water from the storage tank is pumped into the SWS tower. Steam heat is applied to the stripper to remove H₂S and NH₃ from the water. The stripper overhead gas containing H₂S and NH₃ is sent to the new SRU for sulfur recovery and incineration of NH₃.

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 (H₂S) to SO₂, 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 SO₂ 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 H₂S 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 H₂S and SO₂ 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 H₂S 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 SO₂ in the tail gas to H₂S. After passing through the quench tower, the stream enters an amine absorber where H₂S 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.

E. Additional Information

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

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the ARM and are available upon request from 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 applies to Boilers #10, #11, and #12.
 - c. Subpart J - Standards of Performance for Petroleum Refineries shall apply to the SRU Incinerator Stack (E-407 & INC-401), Fractionator Feed Heater Stack (H-202), Reactor Charge Heater Stack (H-201), the FCCU Regenerator, and all fuel gas combustion devices, as applicable, with the exception of the Naphtha Unifier Splitter Heater, the Hydrogen Reformer Heaters (H-101 and H-102), the Alkylation Hot Oil Belt Heater, the Loading Rack Vapor Combustion Unit, and the Refinery Flare (CHS Consent Decree paragraphs 55, 57, and Appendix F).
 - d. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 shall apply to Boiler #12, the Platformer Splitter Reboiler (P-HTR-30, and the Refinery Flare (once new connections are made). Note: Portions of Subpart Ja are currently stayed until February 24, 2009. EPA has proposed revisions to Subpart Ja with respect to certain provisions for flares. Once the stay is lifted or final revised Subpart Ja provisions are promulgated, those final provisions affecting flares will apply to the Refinery Flare.
 - e. Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries shall apply to the HDS Complex, including, but not be limited to, the SRU Incinerator Stack (E-407 & INC-401), Superior Clean Burn II 12 SGIB (C201-B), Fractionator Feed Heater Stack (H-202), Reactor Charge Heater Stack (H-201), the Reformer Heater Stacks (H-101 and H-

102), refinery fuel gas supply lines to the Boilers #10, and #12, the fugitive ULSD Unit and Hydrogen Plant fugitive piping equipment, the Zone A TGTU fugitive piping equipment in VOC service, the Delayed Coker Unit fugitive piping equipment in VOC service and the Naptha Hydrotreating Unit and any other applicable equipment constructed or modified after January 4, 1983.

- f. Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, shall apply to all of the fugitive VOC emitting components added in the Benzene Reduction Unit project and any other applicable equipment constructed, reconstructed, or modified after November 7, 2006.
 - g. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply, but not be limited to, the HDS Complex, SRU Incinerator Stack (E-407 & INC-401), Superior Clean Burn II 12 SGIB (C201-B), Fractionator Feed Heater Stack (H-202), Reactor Charge Heater Stack (H-201), the Reformer Heater Stacks (H-101 and H-102), the ULSD Unit and Hydrogen Plant wastewater streams, the Zone A TGTU process drains, the Delayed Coker, the Zone E SRU/TGTU/TGI, the Benzene Reduction Unit, and any other applicable equipment. NSPS Subpart QQQ does not apply to boiler #10, since the boiler drains will not contain any oily wastewater.
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 shall apply to, but not be limited to, the Product Loading Rack, tank 96 when it is utilized for gasoline service, and certain parts of the Benzene Reduction Unit.
 - 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

- 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.

6. 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 October 22, 2010 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). For administrative convenience, this modification includes information, limitations, and conditions for two separate and unrelated projects. The projects entailing this modification will not cause a project-related emissions increase greater than significance levels and, therefore, does not require a New Source Review (NSR) analysis.

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.

The current permit action is not considered a major modification because the increase in per project emissions is less than significance levels. Therefore, the requirements of this subpart are not applicable.

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 #1821-23 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, GGG, GGGa, and QQQ).
 - e. This facility is subject to current NESHAP standards (40 CFR 61, Subpart FF and 40 CFR 63, Subparts R, CC, UUU, and ZZZZ).
 - f. This source is not a Title IV affected source, nor a solid waste combustion unit.
 - g. This source is not an EPA designated Title V source.

Based on these facts, the Department determined that CHS is a major source of emissions as defined under Title V and currently operates under Operating Permit #OP1821-05, which was issued final and effective on May 21, 2010. The changes associated with this permit action will be incorporated into the next Operating Permit modification.

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. 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 µg/m ³	Cancer ELCR Chronic	Non-Cancer Hazard Quotient Chronic Acute
Benzene*	4.67E-02	8.3E-06	3.9E-07ND
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
Napthalene	1.60E-05	ND	ND ND
Biphenyl	7.98E-08	ND	ND ND
Total Risks =	0.186	8.3E-06	3.9E-07ND

*The reference concentration for Benzene is 71 µg/m³ (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.

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, Permit #1821-13

Chemical Compound	Modeled Conc. µg/m ³	Table 1* Conc.1 µg/m ³	Table 2* Conc. µg/m ³
Benzene	1.81E-02	1.20E-02	7.10E-01
Ethyl Benzene	8.29E-04	--	1.00E+01

Napthalene	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. $\mu\text{g}/\text{m}^3$	Table 1* Conc.1 $\mu\text{g}/\text{m}^3$	Table 2* Conc. $\mu\text{g}/\text{m}^3$
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 effect this determination. Therefore, the Department determined that the health risk assessment model demonstrated negligible risk to public health in this case.

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.

A BACT analysis was submitted by CHS in MAQP application #1821-23, addressing some available methods for controlling emissions from each new or modified source. The following control options have been reviewed by the Department in order to make the following BACT determination.⁴

Process Heater BACT

The H-102 Reformer Heater will be a new refinery fuel gas fired process heater with a rated capacity of 86.2 MMBTU-HHV/hr. As part of the expansion of the 100 Unit Hydrogen Plant, the heater will be installed in parallel with the existing H-101 Reformer Heater. During normal operation, a tailgas stream generated within the 100 Unit Hydrogen Plant, PSA tail gas, is expected to provide approximately 80% of the fuel (BTUs) to the H-102 Reformer Heater. Natural gas or refinery fuel gas will provide the remaining fuel during normal operation and will be used exclusively during unit startup.

The new FCCU Charge Heater will be a new refinery fuel gas fired natural draft process heater with a rated capacity of 60 MMBTU-HHV/hr.

Each proposed heater is a source of fuel combustion related emissions, including NO_x, SO₂, CO, VOC, and PM/PM₁₀.

Various available BACT databases were utilized to review prior BACT determinations for petroleum refinery process heaters. The methods of controlling each of the aforementioned combustion related emissions were reviewed and helped define the range of potentially applicable emissions controls for the pollutants emitted in significant quantities from the new process heaters.

NO_x BACT Analysis

NO_x are formed as part of the combustion process and are generally classified 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 burner, process heater, or boiler's fire box/combustion chamber design, flame temperature, residence time at flame temperature, combustion pressure, and fuel/air ratios in the primary combustion zone. The rate of thermal NO_x formation is an exponential function of 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 of 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. Refinery fuel gas contains negligible amounts of fuel bound nitrogen. As such, thermal NO_x is the predominant type of NO_x that will be formed in the proposed heaters.

The following NO_x control technologies have been identified as commercially available for refinery process heaters: low nitrogen fuels, water-injection style burners, burners with air to fuel ratio control, low NO_x burners (LNB), ULNB including burners with internal or external flue gas

⁴ A significant portion of this BACT analysis has been replicated from *Application for Amendment of Air Quality Permit 1821-22 and Operating Permit OP1821-05, Mild Hydrocracker Project, CHS, Inc., October 2010, Application prepared by CHS and RTP Environmental Associates, Inc.*

recirculation (FGR), Next Generation ULNB including burners with lean premix technology combined with external FGR, EM_x (formerly SCONO_x), non-selective catalytic reduction (NSCR), selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR), some of which can be used in combination with each other.

SNCR, or ammonia injection, is not considered technically feasible in this application because of the temperature zone requirements for SNCR to be effective (in general 1,600-1,900 °F). The exhaust temperature of each new heater will be below the acceptable range. As such, exhaust heating systems and large energy expenditures would be necessary to allow proper abatement system operation. Therefore, SNCR was not analyzed further.

The top control technology, SCR plus combustion controls (i.e. ULNB installation), carries an incremental cost-effectiveness of \$38,000 per ton of NO_x removed. These costs are economically prohibitive and, for this reason, SCR was rejected as NO_x BACT for both the H-102 Reformer Heater and the new FCCU Charge Heater. The use of SCR without combustion controls is not considered feasible or realistic for either heater because each heater will be equipped with ULNB as part of its design.

Combustion control by way of ULNB is proposed as NO_x BACT for both the H-102 Reformer Heater and the new FCCU Charge Heater. A NO_x performance level of 0.03 lb NO_x/MMBtu on a rolling 365-day average was determined to be technically achievable for the new H-102 Reformer Heater and 0.035 lb NO_x/MMBtu on a rolling 365-day average was determined to be technically achievable for the new FCCU Charge Heater. Therefore, the Department has determined that ULNB with a NO_x emissions limitation of 0.03 lb/MMBtu-HHV on a rolling 365-day average constitutes NO_x BACT for the H-102 Reformer Heater and ULNB with a NO_x emissions limitation of 0.035 lb/MMBtu-HHV on a rolling 365-day average constitutes NO_x BACT for the new FCCU Charge Heater.

SO₂ BACT Analysis (H-102 Reformer Heater)

SO₂ emissions from process heaters 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 small extent SO₃. CHS plans to use low sulfur pressure-swing absorber (PSA) tailgas and refinery fuel gas, which will limit SO₂ emissions from this unit.

Emissions of SO₂ from process heaters 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. Post-combustion control for SO₂ involves treating the combustion gases with an alkaline reagent which reacts with the SO₂ to produce a sulfur salt byproduct. 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, generally because FGD is a more cost-effective means of reducing SO₂ emissions.

Pipeline quality natural gas has very low sulfur content, generally in the form of mercaptans used for odorization and trace quantities of reduced sulfur compounds. SO₂ emissions from natural gas-fired equipment are generally considered the lowest practically achievable for that fuel and do not require additional control equipment.

Refinery fuel gas has higher sulfur content than the natural gas purchased from a pipeline. The refinery gas sulfur content is dependent on the removal efficiency of the fuel gas amine scrubbing units in a refinery. For the H-102 Reformer Heater, CHS will use two sources of fuel, PSA tailgas and RFG. It is expected that, on average during normal heater operation, over 80% of the BTUs required for the heater will come from PSA tailgas, a process stream produced within the

hydrogen purification section of the Hydrogen Plant. PSA tailgas is comprised of CO₂, CO, methane, N₂ and H₂. PSA tailgas contains no sulfur compounds because it is generated as part of the reforming process that converts natural gas to hydrogen. Because sulfur is a poison to the catalyst used in the reforming process, the natural gas feed stream is first passed through sulfur absorbers to remove any sulfur or sulfur containing compounds. As a result, the byproduct PSA tail gas contains no sulfur. The remaining fuel that will be fired in H-102 will be RFG, if available, or natural gas. CHS plans to operate the existing amine scrubbing system to produce refinery gas with less than 60 ppmv H₂S, on an annual average basis (NSPS Subpart Ja). On a short-term basis, variability in the operation of the amine scrubbing system may result in spikes in the sulfur concentration of the lean gas produced (i.e, as much as 162 ppmv sulfur on a 3-hour average basis).

FGD is commonly used for control of SO₂ from solid fuel-combustion, such as coal or heavy oil fired sources. FGD technology can be achieved through a variety of wet or dry scrubbing processes. It has demonstrated control efficiencies of up to 95% on coal-fired combustion systems. The use of FGD is not cost effective and is not considered technically feasible and would also require the design of the process heater to be significantly altered. In addition, FGD technology is not commercially demonstrated on small refinery combustion devices because it is cost-prohibitive compared to the cost of desulfurizing the fuel gas.

The top-performing feasible SO₂ control technology is the firing of sulfur-free PSA tailgas in the heater, with the remainder of the fuel required being purchased natural gas, because of the very low sulfur content of natural gas. The next most effective control technology is to maximize the firing of sulfur-free PSA tailgas in the heater, with the remainder of the fuel required being amine treated refinery fuel gas (RFG) that meets the recently promulgated NSPA Ja.

The cost effectiveness of using sulfur-free PSA tailgas and purchased natural gas amounts to \$1.36 million/ton SO₂, based on a natural gas price of approximately \$5/MMBtu. As such, this option is not considered cost effective, and is rejected as BACT. The following constitutes SO₂ BACT for the H-102 Reformer Heater:

- All available 100 Unit PSA tailgas shall be fired in the H-102 Reformer heater
- No sulfur in the PSA tailgas
- Refinery fuel gas H₂S content of 60 ppmv (365-day rolling average).

SO₂ BACT Analysis (New FCCU Charge Heater)

SO₂ emissions from process heaters 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 small extent SO₃. CHS plans to use low sulfur refinery fuel gas, which will limit SO₂ emissions from this unit.

Emissions of SO₂ from process heaters 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. Post-combustion control for SO₂ involves treating the combustion gases with an alkaline reagent which reacts with the SO₂ to produce a sulfur salt byproduct. 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, generally because FGD is a more cost-effective means of reducing SO₂ emissions.

Pipeline quality natural gas has very low sulfur content, generally in the form of mercaptans used for odorization and trace quantities of reduced sulfur compounds. SO₂ emissions from natural gas-fired equipment are generally considered the lowest practically achievable for that fuel and

do not require additional control equipment.

Refinery fuel gas has higher sulfur content than the natural gas purchased from a pipeline. The refinery gas sulfur content is dependent on the removal efficiency of the fuel gas amine scrubbing units in a refinery. CHS plans to operate the existing amine scrubbing system to produce refinery gas with less than 60 ppmv H₂S, on an annual average basis (NSPS Subpart Ja). On a short-term basis, variability in the operation of the amine scrubbing system may result in spikes in the sulfur concentration of the lean gas produced (i.e, as much as 162 ppmv sulfur on a 3-hour average basis).

FGD is commonly used for control of SO₂ from solid fuel-combustion, such as coal or heavy oil fired sources. FGD technology can be achieved through a variety of wet or dry scrubbing processes. It has demonstrated control efficiencies of up to 95% on coal-fired combustion systems. The use of FGD is not cost effective and is not considered technically feasible and would also require the design of the process heater to be significantly altered. In addition, FGD technology is not commercially demonstrated on small refinery combustion devices because it is cost-prohibitive compared to the cost of desulfurizing the fuel gas.

The top-performing feasible SO₂ control technology is the firing of 100% purchased natural gas in the heater, 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 meets the recently promulgated NSPA Ja.

The cost effectiveness of firing natural gas vs. refinery fuel gas in this heater amounts to \$1.36 million/ton SO₂, based on a natural gas price of approximately \$5/MMBtu. As such, this option is not considered cost effective, and is rejected as BACT.

An annual average refinery fuel gas H₂S content of 60 ppmv constitutes SO₂ BACT for the new FCCU Charge Heater, and is also the NSPS Subpart Ja limit for refinery fuel gas combusted in a fuel gas combustion device.

CO and VOC BACT Analysis

In an ideal combustion process, all of the carbon and hydrogen contained within the fuel are oxidized to carbon dioxide (CO₂) and water (H₂O). The emission of CO and VOC in a combustion process is the result of incomplete organic fuel combustion. Operating conditions such as low temperatures, insufficient residence time, low oxygen levels due to inadequate mixing, and/or a low air-to-fuel ratio in the combustion zone result in CO formation. CO emissions may also increase at reduced firing rates due to lowering of flame temperatures and less efficient combustion. VOC emissions result from incomplete combustion of heavier molecular weight components of the refinery fuel gas. In addition, VOC emissions are produced to some degree by the reforming of hydrocarbon molecules in the combustion zone.

Control options for CO and VOC generally consist of fuel specifications, combustion modification measures, or post-combustion controls. Fuel specifications for refinery combustion devices have stipulated the use of natural gas or liquefied petroleum gas (LPG). These fuels have very consistent compositions/heating values which make it easier to tune burners. Also, the hydrocarbon makeup of the fuel can affect the impact of uncombusted fuel on the flue gas VOC content. Combustion controls (proper design and operation) are the most typical means of controlling VOC and CO emissions. For gaseous fuel combustion sources, oxidation catalyst may be used to complete the oxidation of CO to carbon dioxide and water. Emission control methods for CO and VOC that are commercially available for refinery process heaters and boilers include, in order of increasing control effectiveness:

- Burner design and operation
- Fuel specifications (natural gas, LPG, or refinery fuel gas)
- Catalytic oxidation, and
- EM_x (formerly SCONO_x).

Implementation of proper burner design to achieve good combustion efficiency in heaters and boilers will minimize the generation of CO and VOC. Good combustion efficiency relies on both hardware design and operating procedures. A firebox design that provides proper residence time, temperature and combustion zone turbulence, in combination with proper control of air-to-fuel ratio, are essential elements of a low-CO and low-VOC technology.

ULNB technology has advanced significantly, driving down NO_x and CO emissions to lower levels. However, at some level a trade-off exists between low NO_x and low CO emissions. Attempting to tune an ULNB for both low NO_x and low CO can result in unsteady emissions or an unsteady flame, neither of which is desirable. While tuning a burner to achieve lower NO_x, the possibility exists that CO emissions will not be minimized. Conversely, an ULNB can be tuned for lower CO emissions at the cost of increased NO_x. Achieving low CO becomes especially problematic in large vertical, cylindrical furnaces where temperatures are stratified, thus allowing cool spots for CO to form. VOC emissions do not tend to be as sensitive to low NO_x levels as CO but can still be similarly affected. Examination of the RBLC database indicates that implementation of combustion design and operating principles to minimize CO and VOC emissions are the only applied BACT measure for process heaters.

Depending on their source, gaseous fuels have differing compositions and specifications that can affect the ability of ULNB technology to achieve complete combustion. Pipeline natural gas is a fuel predominately comprised of methane. An odorant is added to allow easy leak detection of the otherwise odorless gas. It is processed to meet certain specifications such that key combustion parameters are relatively consistent throughout most of the country. These parameters include percent methane, heating value, and sulfur content. The consistent fuel characteristics of natural gas allow ULNBs to operate with the lowest guaranteed VOC and CO emissions.

Refinery fuel gas is a byproduct of the refining operations and is generally consumed on-site. It may contain significant proportions of fuel components other than methane, such as hydrocarbon, ethane, propane, and butanes. Because it is a byproduct of various refinery processes with varying compositions between streams, it is not economically feasible to make the refinery gas meet a specification that is comparable to pipeline natural gas specifications on a day in day out basis. As such, on a day in day out basis, obtainable VOC and CO emission guarantees for ULNBs firing refinery gas may not be as low as guarantees for ULNBs always firing natural gas.

However, there is no measurable difference in the CO and VOC emissions that would result from burning 100% natural gas instead of refinery fuel gas, which has a very similar composition to natural gas. In addition, burning 100% natural gas in these two heaters is economically prohibitive. As such, this control option is rejected from consideration as BACT.

Catalytic oxidation of CO and VOC gases requires a catalyst bed located in the heater or boiler exhaust. These systems are available as modular units that can be integrated into the exhaust duct or stack. For maximum conversion, catalytic oxidation requires elevated temperature conditions for catalytic oxidation of CO, typically between 800 F and 1,200 F. Oxidation of VOCs occurs efficiently in a lower temperature range of 300 F to 800 F. In some cases, the temperature criterion limits adaptability of process units and reduces the potential for heat recovery. However, there are newer catalyst systems available that extend the practical temperature range. Reduction efficiencies of 90% and 50% are typical for CO and VOC, respectively. The reduction efficiency for VOC is compound specific.

Oxidation catalysts have traditionally been applied to the control of CO emissions from natural gas fired combustion turbines located in CO nonattainment areas. This technology uses precious metal based catalysts to promote the oxidation of CO and un-burnt hydrocarbon to CO₂. Refinery fuel gas contains sulfur as H₂S, which when burned oxidizes to SO₂. Oxidation catalyst is not applied to sources where sulfur bearing fuels are fired because any SO₂ formed by the combustion process is further oxidized to SO₃ which readily becomes sulfuric acid mist in the atmosphere. This increase in sulfuric acid mist would increase plume visibility and increase the amount of PM₁₀ emitted. The sulfuric acid would also cause rapid corrosion of the control equipment and stack. Thus, oxidation catalyst is not considered feasible for this application.

In addition, the precious metals which are the active components in oxidation catalyst are subject to irreversible poisoning when exposed to sulfur compounds. The only known application of oxidation catalyst to refinery gas fired combustion devices is a combustion turbine application in Southern California firing a mix of refinery gas and natural gas. As such, this control option is not considered technically feasible nor is it demonstrated for this type of application and is rejected from consideration as BACT.

EM_x is second generation SCONO_x NO_x absorber technology. EM_x is a catalyst-based post-combustion control, which simultaneously oxidizes CO to CO₂, VOC to CO₂ and water, and NO to NO₂, subsequently adsorbing the NO₂ onto the surface of a catalyst where a chemical reaction removes it from the exhaust stream.

To date, EM_x has been demonstrated only on natural gas fired combustion turbines. The technology has not been demonstrated on other emissions unit types and has not been demonstrated on units that fire refinery fuel gas. As such, EM_x is not considered to be a technically feasible control option for this source category, and is rejected as BACT for the control of CO and VOC emissions.

Based on this analysis, the one technically feasible control option for CO and VOC control is proper burner design and operation. The CO emission estimates for both heaters are based on 100 ppmvd @ 3% O₂ (0.066 lb CO/MMBtu-HHV). Reduction of CO and VOC will be accomplished by controlling the combustion temperature, residence time, and available oxygen. Normal combustion practices at the CHS refinery will involve maximizing the heating efficiency of the fuel in an effort to minimize fuel usage. This efficiency of fuel combustion will also minimize CO and VOC formation. Consistent with all CO and VOC BACT determinations for refinery fuel gas fired sources found in the RBLC, proper design and good combustion techniques constitute CO and VOC BACT for both new heaters.

PM/PM₁₀/PM_{2.5} BACT Analysis

Particulate matter emissions from process heaters with properly designed and tuned burners are inherently low when gaseous fuels are used. Filterable particulate matter in gas-fired sources that are properly tuned originates from the dust in the inlet air and metal erosion within the sources (e.g., tubes, combustion surfaces, etc.). Sources that are not properly tuned may also produce filterable particulate matter as a result of incomplete combustion of fuel hydrocarbons that agglomerate to form soot particles. These particles pass through the firebox and are emitted in the exhaust gas. Condensable particulate matter can result from oxidation of fuel sulfur (to sulfur trioxide) and from incomplete combustion of hydrocarbons in the fuel. For the purposes of this analysis, all of the particulate matter emitted from the proposed process heaters is assumed to be PM₁₀ and PM_{2.5}. Control options available include:

- proper equipment design and operation
- fuel specification

- post-combustion controls, such as a baghouse or electrostatic precipitator (ESP).

Implementation of proper combustor design and operation to achieve good combustion efficiency in heaters and boilers will minimize the generation of CO, VOC, and filterable particulate matter. Good combustion efficiency relies on both hardware design and operating procedures. A firebox design that provides proper residence time, temperature and combustion zone turbulence in combination with proper control of the air-to-fuel ratio, are essential elements of good combustion control.

A common form of particulate matter control from combustion sources is the requirement to use a specified gaseous fuel (e.g., natural gas). Whereas solid fuel (e.g., coal) produces a larger amount of particulate matter, gaseous fuels are considered clean with respect to generation of particulate matter emissions.

Gaseous fuels have differing specifications, depending on their source. Natural gas is processed to meet certain specifications such that the key combustion parameters are relatively consistent in most parts of the country. PM/PM₁₀/PM_{2.5} emissions from properly designed and controlled natural gas-fired equipment are generally considered the lowest achievable.

Refinery fuel gas is a byproduct of refining operations that is typically processed and consumed on-site without the ability of meeting pipeline natural gas composition specifications. With proper burner design and operation, refinery gas-fired sources can achieve PM/PM₁₀/PM_{2.5} emission levels that approach those of natural gas. Combustion of refinery gas will result in slightly higher PM/PM₁₀/PM_{2.5} emissions than combustion with natural gas because of the higher molecular weight hydrocarbons and the presence of sulfur compounds. The presence of higher molecular weight hydrocarbons in refinery fuel gas makes it more difficult to properly tune the burner to minimize the formation of particulates. The higher level of sulfur compounds in refinery fuel gas results in production of more SO₃, a compound that contributes to condensable particulate matter emissions. As previously noted, for the H-102 Reformer Heater, it is expected that, on average during normal operations, over 80% of the BTUs required for the heater will come from PSA tailgas that is considered to be a sulfur-free fuel. Natural gas or refinery fuel gas will provide the remaining fuel during normal operation and will be used exclusively during unit startup. As such, for this heater it is expected that PM/PM₁₀/PM_{2.5} emissions will be nearly equivalent to emissions expected from firing 100% natural gas.

A baghouse removes particulate from an exhaust stream by passing the gas through a fabric filter bags that are periodically cleaned using any number of techniques such as high pressure reverse flow air pulses, high intensity sonic horns and shaking. A baghouse is generally capable of achieving the lowest particulate emission rates of any type of add-on particulate control device.

An electrostatic precipitator (ESP) uses electrodes to collect particulate by impressing a static electric charge on the particles as they pass through the high intensity electric field called a corona, which forms around the corona wire. The particles are then attracted to and collect on electrically charged plates. These plates are periodically rapped by solenoid-activated weights that rap on the top end of the plates to dislodge the collected particles. The materials then falls by gravity into hoppers below the ESP and are removed for disposal. The ability of an ESP to remove particulate matter depends in large part on the electrical properties of the particle itself; the sulfur content of the particle directly impacts those properties. Inorganic particles that are higher in sulfur content are more electrically conductive and are very readily collected by an ESP. In contrast, soot particles formed by condensation after partial combustion of gaseous fuel, have relatively lower sulfur content and are essentially non-conductive. Such particles are not readily captured by electrostatic collectors.

The size of the particulate is also of great concern since very small soot particles are influenced almost equally by impacts with gaseous molecules or electrostatic forces and will be less efficiently captured. Capture is more efficient with larger particles. Although ESPs can also achieve very low particulate emission rates, the achievable emission rates from an ESP are higher than the particulate concentration expected from the combustion of gaseous fuels. As such, ESPs are not used for particulate control for combustion devices burning natural/refinery gas.

The use of baghouses and ESPs for post-combustion controls is common on residual oil and coal-fired combustion units that require significant particulate matter reduction, and which typically have much higher particulate loading, solid particle sulfur content, and larger sized particles. Baghouses and ESPs have not been used for particulate control for combustion devices burning gaseous fuels such as natural gas or refinery fuel gas.

While these controls are theoretically feasible for application to gas-fired boilers, fabric filters and ESPs are not considered technically feasible for the control of PM/PM₁₀/PM_{2.5} emissions from gas fired boilers. These controls would not be expected to provide any significant emissions reductions because of the already low particulate matter emission rate and the fine particle size of the emissions from these units. The fact that such controls have not been applied to similar sources is a clear indication of technical infeasibility. Additional technical support for this conclusion is outlined below.

Fabric filters rely on the build-up of a filter cake to act as a filtering medium for collection of particulate matter. Periodically, this filter cake is removed and filtration efficiency declines until a filtering cake can be re-established. The ultra-fine size of particulate emissions from firing of gaseous fuels is such that no cake could be established in a fabric filter. Instead, the very fine particles would be expected to either pass through the bags uncontrolled, or they would blind filter bags fairly quickly, resulting in unacceptable pressure drops and requiring impossibly frequent bag replacement.

ESPs rely on the ability of a particle to acquire an electrical charge. Once charged, the particles migrate from the flue gas to oppositely charged plates where they deposit. The deposits are removed by rapping the plates and they settle by gravity to collection hoppers. The organic nature of the ultra-fine particulates generated by gaseous fuel combustion is such that acquiring the necessary electrical charge is difficult. ESPs also rely on gravity settling of the collected particulates. The fine particles produced in gas-fired boilers are such that gravity settling is unlikely to occur and any particles collected on the plates would likely be re-entrained in the flue gas as the plates are rapped.

The top-performing feasible PM/PM₁₀/PM_{2.5} control technology is the firing of 100% purchased natural gas in the boiler, because the very low sulfur content of natural gas will result in low condensable PM₁₀ and PM_{2.5} emissions relative to the use of refinery fuel gas. The majority of fuel to be fired in H-102 Reformer Heater will be PSA tailgas which, due to its composition, will result in PM₁₀ and PM_{2.5} emission rates similar to those expected from firing 100% natural gas. The next most effective technically feasible PM/PM₁₀/PM_{2.5} control option is the use of good combustion practices in combination with firing gaseous fuels.

The calculated cost of firing 100% purchased natural gas, per ton of PM₁₀ or PM_{2.5} reduced as a result, is greater than \$30 million/ton PM₁₀ or PM_{2.5} based on a natural gas price of approximately \$5/MMbtu. As such, this option is not considered cost effective and is rejected as BACT.

Consistent with all PM/PM₁₀/PM_{2.5} BACT determinations for refinery fuel gas fired sources found in the RBLC, proper design and good combustion techniques constitute PM/PM₁₀/PM_{2.5} BACT for the new process heaters.

Zone D Sulfur Recovery Unit/Tailgas Treating Unit BACT

SRU BACT Analysis

Potentially applicable control technologies were identified using EPA's RACT/BACT/LAER Clearinghouse (RBLC) database, existing permits and permit applications, and other publicly available information. Several technologies are used to recover sulfur and are either marketed and/or in commercial use. The objective of this BACT analysis was to determine which technology or technologies are potentially applicable to the existing/expanded Zone D SRU/TGTU configuration that is currently complying with an annual SO₂ limit of 125 ppmvd at 0% O₂ on a daily rolling 365-day average. Criteria used in the context of this evaluation included the following:

- Engineering chemical and physical limitations analysis of the technology's feasibility: An analysis was made to determine if there was a chemical or physical limitation that precludes the technology from being applied to this application.
- The retrofit ability of the technology to the existing Zone D SRU/TGTU: For the purpose of this analysis, changes that could be made to the existing SUR and add-on control technologies that could be applied downstream of the existing SRU (i.e., TGTU) were included for further consideration in the analysis. A common sense approach was used that eliminated any technologies that required the replacement of the entire existing SRU or modification to the upstream refinery operation or processes. This would require the unnecessary replacement of functioning equipment.

The NSPS level of 250 ppmvd cannot solely be achieved by several of the technologies. The basis for this statement is found in the following discussion from AP-42 that relates the volumetric NSPS standard to an equivalent sulfur plant efficiency:

Existing new source performance limit sulfur emissions from Claus sulfur recovery plants of greater than 20.32 mega gram per day capacity to 0.025 % by volume...This is comparable to the 99.8 to 99.9 % control level for reduced sulfur.

AP-42 Fifth Ed., Ch. 8.13, p. 4 (1998).

With respect to multi-stage Claus option, it is important to note that the Zone D SRU is currently configured as a 3-stage unit. There are several technologies (i.e., Super Claus®, MCRC®, Clinsulf®, and Selectox) that are refinements to the multi-stage Claus approach currently operating at the Zone D SRU/TGTU. Because each of these technologies achieves similar sulfur recovery efficiencies prior to the TGTU in a somewhat different manner with regards to how they promote the Claus reaction operating conditions, it is not technically feasible to combine them in series. These technologies provide refiners looking to add new SRU capacity in the form of new units with additional options from which to choose. Replacement of the existing Claus portion of the SRU with one of these processes is not considered within the bounds of this BACT analysis because BACT is assumed to apply to replacement of components of the modified unit and not replacement of the entire unit (e.g., NOX BACT on a boiler looks at replacement of the burners not replacement of the boiler). In addition, the NSPS SO₂ emission level (99.8 to 99.9%) cannot be achieved solely by application of these technologies.

An additional identified technology, Sulferox, is a completely different approach to reducing sulfur that would require abandonment of the amine absorption system used to remove H₂S from refinery fuel gas. In addition, this system would not be applicable to the sour water stripper overhead gas. As such, it is considered technically infeasible.

Both TGTU and Marsulex are capable of achieving the NSPS SO₂ emission level. However, replacement of the existing TGTU with the Marsulex process is not considered within the bounds of this BACT analysis because BACT is assumed to apply to replacement of components of the modified unit and not replacement of the entire unit (e.g., NO_x BACT on a boiler looks at replacement of the burners not replacement of the boiler).

One potential approach not yet presented is the use of a lower sulfur crude to reduce SRU emissions. Using a crude oil supply that contains lower weight percent sulfur can reduce emissions (in terms of lbs) of H₂S and SO₂ from the refinery. A feedstock with lower weight percent sulfur will result in proportionately lower emissions of H₂S and SO₂ per unit of crude that is processed because less acid gas will be generated and less sulfur recovered. However, reducing the crude sulfur content does not reduce the level of SO₂ and H₂S emissions per unit of sulfur that is processed. Thus, this option would not reduce the concentration of SO₂ in the incinerator stack.

Furthermore, the sulfur content of the crude oil processed at a refinery is dependent on the feedstock supply that is economically available, meets contractual specifications, and is compatible with refinery operations. In particular, the CHS Refinery is an asphalt refinery, which means that to operate and produce this product it must purchase crudes that are high in their asphalt content. The defined need to purchase these types of crudes, in turn, defines the sulfur content of the crude entering the refinery. In conclusion, consideration of lower sulfur crude feedstock may be appropriate for a BACT analysis for a new or reconstructed refinery, but is entirely inappropriate for an existing refinery's SRU BACT analysis.

The following control technologies are considered technically feasible control alternatives:

- Multistage Claus trains followed by a tailgas treating unit (TGTU). As previously described the Zone D SRU is currently comprised of a three stage Claus unit followed by a TGTU.
- Multistage Claus trains followed by a tailgas treating unit (TGTU) which is then followed by a wet gas scrubber technology (i.e., Marsulex or caustic based WGS).

The proposed project entails switching to a more selective amine in the TGTU. Based upon vendor modeling scenarios, this amine is expected to allow CHS to operate the expanded SRU (i.e., from 65 to 93.8 LTPD) such that the exhaust gas concentration of 113.2 ppmvd SO₂ @ 0% O₂ can be achieved on an annual basis. This level of control corresponds to a 99.96% sulfur recovery efficiency.

The next step in the analysis is to determine the achievable emissions rate associated with the technically feasible alternatives. This information is used to rank order the alternatives in a top-down hierarchy (i.e., from most to least stringent). In some cases, due to the case-by case nature of BACT, there may be multiple control levels identified for the same technology. In those cases, the most stringent control level is evaluated first. If it is eliminated due to environmental, energy, or cost impacts, then the next most stringent control level is evaluated. The least stringent alternative that can be selected as BACT is the NSPS level. Since the Zone D SRU is subject to the NSPS Subpart J SO₂ requirement found at 40 CFR 60.104 (i.e., 250 ppmvd SO₂ @0% O₂ on a rolling hourly 12-hour average basis), this is the least stringent level that can be evaluated.

To determine the hierarchy of precedents for the feasible controls, available information sources including the RBLC and other information sources were surveyed. The form of the permit limits varies greatly across the identified SRU precedents. The identified precedents are rank ordered

from most to least stringent using the following four categories:

- Concentration based BACT limits that were more stringent than the NSPS,
- Percent recovery efficiency based limits,
- Limit which appear to be equivalent to the NSPS requirement of 250 ppmvd SO₂ @ 0% O₂, and
- Mass rate based emissions limits.

Because there were several precedents based on the oxygen corrected stack SO₂ concentration, which is the form used for the NSPS, as well as the current Zone D SRU limit, the evaluation focused first on these precedents.

The two most stringent precedents identified rely upon wet gas scrubbing to achieve the required level of control. Both of these precedents were identified through the South Coast Air Quality Management District. These precedents were considered as part of a Best Available Retrofit Control Technology (BARCT) study. No information related to averaging time was included in the reports.

The next most stringent concentration based precedent is for Marathon Garyville. To learn more about this precedent, site personnel at the refinery were contacted by CHS. Based on information obtained during the call, the precedent is for a new SRU which was constructed as part of a refinery expansion and the 93.41 ppmvd @ 0% O₂ is not considered a limit. Instead, the SO₂ concentration was used to derive a mass emissions limit for the new SRU based on full load operation. As a result, because a mass emissions limit does not consider operation at reduced loads when the volumetric flow rate is much less and compliance can be demonstrated at higher exit concentration, this precedent was eliminated from consideration.

The Williams Shelby Tennessee precedent is also for a new SRU unit. Per CHS, contact with the Tennessee Department of Natural Resources confirmed that this unit was built and has been operating in compliance with its limit. The final precedent identified that is more stringent than the current BACT for the Zone D SRU/TGTU is the limit for the Conoco (Jupiter) Billings SRU. Only the short-term 12-hour limit is more stringent than the current CHS limit. These precedents are considered further as part of the impacts analysis that follows.

The only other precedent that was identified as potentially more stringent than the CHS proposed limit of 113.2 ppmvd @ 0% O₂ (99.965 sulfur recovery efficiency) was the Exxon Baton Rouge, LA precedent which listed a 99.99% sulfur recovery efficiency for a Flexsorb-SE based absorber using Beavon technology. Because this precedent is not for a unit based upon Claus reactors followed by an amine based TGTU and the sulfur recovery efficiency was not listed as a limit and was eliminated from consideration.

The remaining precedents were not considered further by this analysis because they were not considered as stringent as the current Zone D SRU/TGTU limits.

As shown, SO₂ concentration is used as the primary ranking criteria in the hierarchy. This form of the limit was chosen as the basis for the hierarchy because it is consistent with the form of the NSPS limit as well as the current and other Montana precedents. There is also a hierarchy related to the required averaging time. For the annual averaging time (i.e., daily rolling 365-day average), the hierarchy includes three control levels: <12, 75, and 125 ppmvd @0% O₂. For the short-term averaging times (i.e., 12-hour and 24-hour) the hierarchy includes four possible levels: <12, 159, 167, and 250 ppmvd @0% O₂. For purposes of BACT both a short and long term limit is required. The discussion in support of the annual averaging time is presented first. Annual averaging times can be directly translated to annual tons. As a result, the presentation of cost effectiveness is directly related. For SRU's short-term limits are in part defined by the design

basis of the SRU that is defined to achieve a given operating level as well as other impacts that can occur to the given SRU at a given refinery due to the refinery's configuration and daily operation.

The most stringent precedent for both averaging times is based on the use of wet gas scrubbing (WGS). The BARCT study for this technology presents a capital cost of \$11,000,000 to \$13,000,000 associated with the installation of WGS technology on a 50 LTPD SRU. The emissions reductions that would be achieved by installing WGS technology on the proposed expanded Zone D SRU/TGTU (93.8 LTPD) would be equivalent to 31 tons/year. If no annual operating costs are assumed and the increased cost of capital associated with installation of the WGS is not included the annualized capital associated with the installation of WGS technology would be \$1,460,000 and the corresponding cost effectiveness would be \$47,000 per ton of SO₂ removed. This cost effectiveness value is considered unreasonable and as a result this option is removed from consideration.

As part of the proposed project the following changes/upgrades will be made to the Zone D SRU/TGTU to allow its capacity to be expanded from a capacity of 65 to 93.8 LTPD:

- Upgrade the control system from a manually adjusted feedback trim system to a fully automatic feedforward with feedback control system,
- Upgrade the acid gas burner such that it incorporates state-of-the-art technology (SOTA) with regards to its ability to control the stoichiometric combustion of acid gas (i.e., H₂S and ammonia),
- Upgrade the furnace such that it can operate at a higher pressure and temperature,
- Upgrade the reheaters in the Claus unit from fired to steam based reheaters,
- Replace the TGTU quench column and adsorber column trays with a design capable of handling higher gas volumes,
- Improve the TGTU cooling system such that the circulating amine temperature is kept below 100°F, and
- Replace the MDEA used in the TGTU adsorber with a proprietary high performance amine.

As previously noted, the primary keys to lower SO₂ emissions from the SRU process are the recovery of H₂S in the TGTU and the minimization of carbonyl sulfide (COS) and carbon disulfide (CS₂) as part of the sulfur recovery process. The H₂S recovery is defined by the ability of the amine to remove H₂S in the TGTU absorber and recycle it back to the front of the SRU. The retraying, improved cooling and use of a proprietary high performance amine in place of MDEA will ensure SOTA control of H₂S. The amount of COS and CS₂ entering the TGTU will be minimized through the use of SOTA burner technology and controls as well as the use of steam rather than fired reheaters (i.e., fired reheaters serve as a carbon source for the formation of COS and CS₂). Based on the preliminary design studies conducted by the SRU vendor, the expanded improved SRU is expected to have start of run emissions of 75 ppmvd @0% O₂.

Following these changes, the expanded Zone D SRU/TGTU will have the characteristics of a SOTA SRU/TGTU. To account for a deterioration in the performance of the TGTU hydrogenation reactor catalyst, which is key to the ability to keep SO₂ emissions low, and to accommodate for normal system fluctuations (i.e., changes in the ability to operate the SRU at steady state, changes in refinery crude quality), a 50 percent safety factor has been applied to the vendor expected performance. A resulting Zone D SRU/TGTU SO₂ annual emissions level of 113.2 ppmvd @ 0% O₂ is used for purposes of this BACT analysis.

The only more stringent annual control level is the 75 ppmvd level. Operation at the 75 ppmvd level would result in a 10.3 ton per year SO₂ reduction from the 113.2 ppmvd level. As an indicator using a cost effectiveness criteria of \$10,000/ton, the capital cost associated with the upgrades required to guarantee this level would need to be accomplished for less than ~\$1,000,000 in order to stay below this level. Based on the estimated cost of the proposed improvements, it can be concluded that this improved level of control cannot be achieved for less than \$1,000,000. As a result the 75 ppmvd level is removed from consideration as cost unreasonable and a limit of 113.2 ppmvd @0% O₂ on a daily rolling 365-day average is proposed as BACT.

With regards to short-term averaging time BACT levels, there are two more stringent precedents, one at 150 ppmv (Williams – TN) and one at 167 ppmv (Conoco (Jupiter) – Billings). No additional information is available with regards to how the Williams level was arrived at as part of the BACT process. CHS understands that the short-term Conoco (Jupiter) limit was proposed at the time the SRU/TGTU was added to existing sulfur handling facilities as part of a gasoil hydrotreater project and was based on the design of the unit.

It is difficult to predict the short-term performance of a new or modified SRU because the results are refinery specific based on the amount of hydrocarbon that may reach the SRU/TGTU on an intermittent basis, the variations in acid gas loading and the rate of change when those variations occur, and the concentration of ammonia in the acid gas and the rate of change in the ammonia rate.

To better understand the impact of these variations in the operation of the existing Zone D SRU/TGTU, daily average data for the past two years were analyzed. The results of this analysis indicate that the existing operation can have daily average SO₂ concentration from 6 to 230 ppmvd. This wide range is indicative of the type of service the Zone D SRU/TGTU sees. In particular, the periods of short-term high SO₂ concentrations are due to periods of increased sulfur and nitrogen loading in the SRU and heavier crudes being run through the refinery. As a result, because these impacts will be seen by the updated/expanded Zone D SRU/TGTU, CHS is proposing 250 ppmvd @0% O₂ as the short-term BACT limit (hourly rolling 12-hour average).

Based on the information presented above, CHS proposes, and the Department concurs, the use of upgraded SOTA tail gas treatment with enhanced amine to achieve an emission rate of 113.2 ppmvd @ 0% O₂ on a daily rolling 365 day average and 250 ppmvd @ 0% O₂ on an hourly rolling 12-hour basis as BACT. This proposed BACT is based on the following:

- Design modifications and operational changes (i.e., improved controls) to the existing Claus Unit's burners and reheat system to minimize the formation of COS and CS₂;
- Design and operation of a TGTU with a hydrogenation reactor that promotes the destruction of COS and CS₂;
- Use of a proprietary amine in the TGTU to minimize H₂S emissions from the TGTU;
- Elimination of wet gas scrubbing based upon an unreasonable cost effectiveness in excess of \$47,000/ton SO₂ removal;
- Elimination of the more stringent TGTU based control level of 75 ppmvd based upon cost effectiveness; and
- Elimination of more stringent short term limits based upon the facility specific operating issues faced by CHS.

Refinery Equipment BACT

As part of the proposed Mild Hydrocracker Project, new pumps, valves, flanges and other refinery equipment will be placed into service. Much of this equipment will have the potential to emit fugitive VOC.

VOC BACT Analysis for Refinery Equipment

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, eliminating the need for a case-by-case determination. 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.

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 recently finalized amendment to NSPS Subpart GGG. The results of this effort indicated a cost of over \$200,000 per ton of VOC controlled.

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:

- 40 CFR 63, Subpart H (i.e., HON NESHAP (Hazardous Organic NESHAP))
- 40 CFR 60, Subpart GGGa (i.e., Refinery NSPS for Construction, Reconstruction or Modification Commenced after November 7, 2006)
- 40 CFR 63, Subpart CC (i.e., Refinery New Source NESHAP)
- 40 CFR 60, 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 the new 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 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.⁵ 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 SOCOMI 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 GGG light liquid/gas vapor valve leak definition from 10,000 ppm to 500 ppm and NSPS 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 GGG connectors leak definition for 10,000 ppm to 500 ppm (i.e., NESHAP HON) was not determined to be cost-effective (i.e., \$20,000/ton).

As a result of 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 is proposed as an effective LDAR program meeting the requirements of NSPS Subpart GGGa. Equipment in VOC service in the Mild Hydrocracker will be subject to NSPS Subpart GGGa and will be included in the refinery's existing LDAR program.

IV. Emission Inventory

The following tables summarize the potential to emit for the proposed projects associated with this permit action. Currently, the existing HDS Unit operates under two scenarios depending on

⁵ See 72 Federal Register 64864-5 (Nov. 16, 2007).

whether diesel or gasoline is the preferred product as dictated by product markets. Following completion of the Mild Hydrocracker Project, CHS will still operate under these scenarios. As such, project related emissions increases have been calculated for each scenario. Table 1 summarizes emissions increases associated with the Mild Hydrocracker Project under the maximum diesel production case. Table 2 summarizes these emissions under the maximum gasoline production case.

Table 1.

Summary of Mild Hydrocracker Project Related Emissions Increases, TPY						
Maximum Diesel Production Case						
	NOx	SO ₂	TSP	PM _{10/2.5}	CO	VOC
New Units						
H-102 Reformer Heater	11.3	0.5	2.8	2.8	25.1	0.3
FCCU Charge Heater	9.2	2.1	1.6	1.6	17.5	1.1
Modified Units						
Zone D SRU/TGTU (process)		9.1				
Zone D SRU Incinerator (fuel)	1.4	0.0	0.1	0.1	1.4	0.1
Fugitive emission components						10.0
Affected Units						
Reformer H-101	2.9	0.0	0.0	0.0	3.6	0.1
H-201 Reactor Charge Heater	0.3	0.0	0.1	0.1	0.0	0.0
H-202 Fractionator Feed Heater	0.3	0.0	0.1	0.1	0.0	0.0
FCCU Regenerator	0.0	0.0	0.0	0.0	18.4	0.0
NHT Charge Heater	0.4	0.0	0.0	0.0	0.1	0.0
NHT Stripper Reboiler #1	0.6	0.0	0.0	0.0	0.5	0.0
NHT Stripper Reboiler #2	0.6	0.0	0.0	0.0	0.5	0.0
NHT Splitter Heater	0.4	0.0	0.0	0.0	0.3	0.0
Platformer Heater	9.6	0.1	0.3	0.3	2.9	0.2
Platformer Debutanizer Heater	0.5	0.0	0.0	0.0	0.5	0.0
Platformer Splitter Reboiler	0.0	0.0	0.0	0.0	0.0	0.0
Storage Tanks						2.6
Loading VCU	0.2	0.0	0.0	0.0	0.3	0.4
Loading Fugitives						0.3
#5 Cooling Tower			0.1	0.1		0.1
Project Affected Emissions Units, Totals						
	37.7	11.9	5.1	5.1	71.1	15.2
PSD Thresholds	40	40	25	15 / 10	100	40
PSD Review Required?	NO	NO	NO	NO	NO	NO

Table 2

Summary of Mild Hydrocracker Project Related Emissions Increases, TPY						
Maximum Gasoline Production Case						
	NOx	SO ₂	TSP	PM _{10/2.5}	CO	VOC
New Units						
H-102 Reformer Heater	11.3	0.5	2.8	2.8	25.1	0.3
FCCU Charge Heater	9.2	2.1	1.6	1.6	17.5	1.1
Modified Units						
Zone D SRU/TGTU (process)		9.1				
Zone D SRU Incinerator (fuel)	1.4	0.0	0.1	0.1	1.4	0.1
Fugitive emission components						10.0
Affected Units						
Reformer H-101	2.9	0.0	0.0	0.0	3.6	0.1

H-201 Reactor Charge Heater	0.3	0.0	0.1	0.1	0.0	0.0
H-202 Fractionator Feed Heater	0.3	0.0	0.1	0.1	0.0	0.0
FCCU Regenerator	0.0	0.0	0.0	0.0	18.4	0.8
NHT Charge Heater	0.1	0.0	0.0	0.0	0.0	0.0
NHT Stripper Reboiler #1	0.1	0.0	0.0	0.0	0.1	0.0
NHT Stripper Reboiler #2	0.1	0.0	0.0	0.0	0.1	0.0
NHT Splitter Heater	0.1	0.0	0.0	0.0	0.1	0.0
Platformer Heater	2.1	0.0	0.1	0.1	0.6	0.0
Platformer Debutanizer Heater	0.1	0.0	0.0	0.0	0.1	0.0
Platformer Splitter Reboiler	0.0	0.0	0.0	0.0	0.0	0.0
Alkylation Hot Oil Heater	0.4	0.0	0.1	0.1	0.5	0.1
Storage Tanks						3.6
Loading VCU	0.2	0.0	0.0	0.0	0.3	0.4
Loading Fugitives						0.4
#5 Cooling Tower			0.1	0.1		0.1
Project Affected Emissions Units, Totals	28.6	11.8	4.9	4.9	67.9	16.9
PSD Thresholds	40	40	25	15 / 10	100	40
PSD Review Required?	NO	NO	NO	NO	NO	NO

As a result of the ULSD Burner Fuel Project, the burner fuel product pumps will be able to recover and pump up to an additional 4,000 barrels per day (BPD). Increases in emissions are associated with tank truck loading and storage tank emissions. There are no increases of emissions with the ULSD unit itself as a result of this project. Emissions increases associated with the ULSD Burner Fuel Project are summarized below.

Table 3

Summary of ULSD Burner Fuel Project Related Emissions Increases, TPY						
Affected Units	NO _x	SO ₂	TSP	PM _{10/2.5}	CO	VOC
Storage Tanks						22.0
Loading VCU	0.5	0.0	0.0	0.0	1.0	2.5
Loading Fugitives						0.2
Project Affected Emissions Units, Totals	0.5	0.0	0.0	0.0	1.0	24.6
PSD Thresholds	40	40	25	15 / 10	100	40
PSD Review Required?	NO	NO	NO	NO	NO	NO

V. Existing Air Quality

There are two areas in Billings (approximately 12 miles northeast of the CHS Refinery) which were federally designated nonattainment for CO (National Ambient Air Quality Standards (NAAQS)) and for the old secondary total suspended particulates (PM) standard. EPA redesignated the Billings CO nonattainment area to attainment on April 22, 2002. The old PM standard has since been revoked and replaced with new PM₁₀ (respirable) standards. The Billings area is listed as not classified/attainment for the new PM₁₀ standard.

The area (2.0 km) around the CHS Refinery in Laurel is federally designated as nonattainment for the SO₂ NAAQS (40 CFR 81.327). Ambient air quality monitoring data for SO₂ from 1981 through 1992 recorded SO₂ levels in the Laurel and Billings areas in excess of the Montana Ambient Air Quality Standards (MAAQS) for the 24-hour and annual averages. In 1993, EPA determined that the SO₂ SIP for the Billings/Laurel area was inadequate and needed to be revised. The Department, in cooperation with the Billings/Laurel area SO₂ emitting industries, adopted a new control plan to reduce SO₂ emissions by establishing emission limits and requiring continuous emission monitors on most stacks. In addition, on April 21, 2008, the EPA issued a federal implementation plan (FIP)

for those SIP provisions it deemed inadequate. The FIP includes additional flare requirements for specified sources. Area SO₂ emissions have since declined between 1992 and 2008. The decline can be attributed to industrial controls added as part of the SIP/FIP requirements, plants operating at less than full capacity, and industrial process changes to meet sulfur in fuel regulations. Ambient air quality monitoring for SO₂, PM₁₀, and CO in the Billings/Laurel area continues.

VI. Air Quality Impacts

The Department did not conduct ambient air modeling for this permit action. The Department believes the current permit action will not cause or contribute to a violation of any ambient air quality standard because emissions from this permit action will not surpass the facility-wide limits that were based on recent historical emissions, which complied with ambient air quality standards.

VII. Ambient Air Impact Analysis

Potential impacts to ambient air quality by the proposed projects were assessed by CHS. Increases in emissions attributed to the two new heaters, H-102 and the replacement FCC Charge Heater, and emissions decreases associated with replacement of the FCCU Charge Heater and C-201B compressor were included in a modeling analysis (EPA-approved AERMOD model). The model was created utilizing five years of meteorological data and default settings. As shown in the table below, the modeled impacts associated with the proposed project fall below the pollutant specific significant impact levels (SILs). Therefore, the proposed project is not anticipated to cause or contribute to an exceedance of the standards.

Table 4

CHS Five Year AERMOD Summary				
Pollutant	Average	Conc. (ug/m ³)	SIL (ug/m ³)	% SIL
NOx	1-hr	6.37	7.6	84.3%
	Annual	0.002	1.0	0.2%
SO ₂	1-hr	1.5	7.8	19.7%
	3-hr	0.5	25.0	2.1%
	24-hr	0.1	5.0	1.9%
	Annual	0.0	1.0	0.1%

VIII. Taking or Damaging Implication Analysis

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

YES	NO	
X		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	X	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	X	3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)
	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)].
YES	NO	
		5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests?

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

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

IX. Environmental Assessment

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

DEPARTMENT OF ENVIRONMENTAL QUALITY
Permitting and Compliance Division
Air Resources Management Bureau
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FINAL ENVIRONMENTAL ASSESSMENT (EA)

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

Permit Number: 1821-23

Preliminary Determination on Permit Issued: 12/10/10

Department Decision Issued: 12/30/10

Permit Final: 01/15/11

1. *Legal Description of Site:* South ½, Section 16, Township 2 South, Range 24 East in Yellowstone County.
2. *Description of Project:* On November 1, 2010, the Department received an application from CHS requesting a modification to MAQP #1821-22.

In this application, CHS proposes to convert the existing Hydrodesulfurization (HDS) Unit into a Mild Hydrocracker. Capacities of the existing 100 Unit Hydrogen Plant and the Zone D Sulfur Recovery and Tail Gas Treatment Units (SRU/TGTU) will be increased, the existing feed heater in the FCC Unit will be replaced and a rate-limiting pressure safety valve (PSV) in the Naphtha Hydrotreating Unit (NHT) will be replaced. Collectively, these modifications are referred to as the “Mild Hydrocracker Project.”

The application also includes information related to an additional project that will be completed at the refinery concurrent with the projects discussed above. The project involves adding the flexibility to recover additional Burner Fuel, rather than Diesel Fuel, within the existing Ultra Low Sulfur Diesel (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.

3. *Objectives of Project:* The primary purpose of this permitting action (converting the existing HDS Unit into a Mild Hydrocracker) will be to produce an increased volume of higher quality diesel fuel by utilizing more hydrogen to convert gasoil into diesel.
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. 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 a BACT determination, would be contained in MAQP #1821-23.

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 table summarizes the potential physical and biological effects of the proposed project on the human environment. The "no action alternative" was discussed previously.

		Major	Moderate	Minor	None	Unknown	Comments
A	Terrestrial and Aquatic Life and Habitats			X			Yes
B	Water Quality, Quantity and Distribution			X			Yes
C	Geology and Soil Quality, Stability and Moisture			X			Yes
D	Vegetation Cover, Quantity and Quality			X			Yes
E	Aesthetics				X		Yes
F	Air Quality			X			Yes
G	Unique Endangered, Fragile or Limited Environmental Resource			X			Yes
H	Demands on Environmental Resource of Water, Air and Energy			X			Yes
I	Historical and Archaeological Sites			X			Yes
J	Cumulative and Secondary Impacts			X			Yes

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 permitting action could have a minor effect on terrestrial and aquatic life and habitats, as the proposed project would include installation of two new emission units (H-102 Reformer Heater, FCCU Charge Heater). Additional emissions are anticipated with a modification to the Zone D SRU/TGTU and emissions attributed to fugitive emission components associated with the equipment and piping being installed with the Mild Hydrocracker Project. Impacts to terrestrial and aquatic life and habitats may occur as a result of these increased emissions. However, the emissions increases per project fall below significance levels identified within the rules associated with PSD. Additionally, the permitting action would result in the incorporation of the most current facility and emissions information available. The overall emissions would remain within the facility-wide emissions caps established in MAQP #1821-05 in 2000. Further, the project would ultimately take place on industrial property that has already been disturbed. Therefore, only minor impacts to terrestrial and aquatic life and habitats are anticipated.

B. Water Quality, Quantity, and Distribution:

While deposition of pollutants would occur, the Department determined that any impacts from deposition of pollutants would be minor. Furthermore, this action would not result in a change in the quality or quantity of ground water. There also would not be any changes in drainage patterns or new discharges associated with this project. Therefore, minor impacts to water quality, quantity, and/or distribution are anticipated.

C. Geology and Soil Quality, Stability, and Moisture:

The proposed project constitutes of installation and/or replacement of emission sources on the same existing industrial site. Therefore, no additional disturbance would be created as a result of the proposed project. While deposition of pollutants would occur, the Department determined that any impacts from deposition of pollutants would be minor. Additionally, no unique geologic or physical features would be disturbed. Overall, we believe that any impact to the geology and soil quality, stability, and moisture would be minor.

D. Vegetation Cover, Quantity, and Quality:

The proposed project would affect an existing, industrial property that has already been disturbed. No additional vegetation on the site would be disturbed for the project. However, possible increases in actual emissions of NO_x, SO₂, VOC, PM/PM₁₀, and CO from historical emission levels may result in minor impacts to the diversity, productivity, or abundance of plant species in the surrounding areas. Overall, any impacts to vegetation cover, quantity, and quality would be minor.

E. Aesthetics:

The proposed modification to the facility would be constructed in the area that has previously been disturbed and would not result in any additional disturbance. Therefore, no impacts to aesthetics are anticipated.

F. Air Quality:

The proposed project would include increases of NO_x, SO₂, VOC, PM/PM₁₀, and CO emissions. However, the per project emissions do not exceed “significance” threshold levels as outlined in the rules associated with PSD. CHS would be required to maintain compliance with the Billings/Laurel SO₂ State Implementation Plan (SIP), current permit conditions, and state and federal ambient air quality standards. Additionally, modeled levels of pollutants for the proposed project show compliance with the NAAQS and the MAAQS. While deposition of pollutants is anticipated, the Department has determined that any air quality impacts as a result of the deposition would be minor.

G. Unique Endangered, Fragile, or Limited Environmental Resources:

The Department, in an effort to assess any potential impacts to any unique endangered, fragile, or limited environmental resources in the initial proposed area of operation (South ½, Section 16, Township 2 South, Range 24 East in Yellowstone County), contacted the Natural Resource Information System – Montana Natural Heritage Program. Search results concluded there are seven species of concern within the area. The search area, in this case, is defined by the section, township, and range of the proposed site, with an additional 1-mile buffer. The known specie of concern includes the Yellowstone Cutthroat Trout (Sensitive).

This permitting action is not expected to have any impacts to terrestrial and aquatic life and/or their habitat; therefore, it is unlikely that unique, rare, threatened, or endangered

species would experience any impacts. The project would occur at a previously disturbed industrial site, within allowable levels of emissions. However, there is a minor increase in potential air emissions, as described in Section 7.F. of this permit, which may have a minor impact on the surrounding area.

H. Demands on Environmental Resource of Water, Air, and Energy:

As described in Section 7.B of this EA, this permitting action would have little or no effect on the environmental resource of water as there would be no discharges to groundwater or surface water associated with this permitting action.

As described in Section 7.F of this EA, the impact on the air resource in the area of the facility would be minor because the facility would be required to maintain compliance with other limitations affecting the overall emissions from the facility.

A minor impact to the energy resource is expected during the construction process involved with the proposed project; however, this impact is temporary. Additional energy consumption as a result of new equipment installation is expected to be minimal by scale. Overall, the impact to the energy resource would be minor.

I. Historical and Archaeological Sites:

In an effort to identify any historical and archaeological sites near the proposed project area for previous projects, the Department contacted the Montana Historical Society, State Historic Preservation Office (SHPO). According to SHPO records, there have been a few previously recorded sites within the designated search locales. In addition to the sites there have been a few previously conducted cultural resource inventories done in the areas. The project would occur within the boundaries of a previously disturbed industrial site. There is a low likelihood cultural properties will be impacted; therefore, any impacts to historical and archeological would be considered minor.

J. Cumulative and Secondary Impacts:

The proposed action would include increases of NO_x, SO₂, VOC, PM/PM₁₀, and CO emissions; however, cumulative and secondary impacts from this action are anticipated to be minor as the emissions do not exceed "significance" threshold levels on a per project basis as outlined in the rules associated with PSD. Additionally, as described in Section 7.F of this EA, the impact on the air resource in the area of the facility would be minor because the facility would be required to maintain compliance with other limitations affecting the overall emissions from the facility. Any cumulative or secondary impacts as a result of this project are considered to be minor and overall emissions will remain within the facility-wide emissions caps established in MAQP #1821-05 in 2000.

8. The following table summarizes the potential economic and social effects of the proposed project on the human environment. The "no action alternative" was discussed previously.

		Major	Moderate	Minor	None	Unknown	Comments
A	Social Structures and Mores				X		Yes
B	Cultural Uniqueness and Diversity				X		Yes
C	Local and State Tax Base and Tax Revenue				X		Yes
D	Agricultural or Industrial				X		Yes

	Production						
E	Human Health			X			Yes
F	Access to and Quality of Recreational and Wilderness Activities				X		Yes
G	Quantity and Distribution of Employment				X		Yes
H	Distribution of Population				X		Yes
I	Demands for Government Services			X			Yes
J	Industrial and Commercial Activity				X		Yes
K	Locally Adopted Environmental Plans and Goals				X		Yes
L	Cumulative and Secondary Impacts			X			Yes

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

A. Social Structures and Mores:

The proposed project would not cause a disruption to any native or traditional lifestyles or communities (social structures or mores) in the area because the project would be constructed at a previously disturbed industrial site. The proposed project would not change the nature of the site.

B. Cultural Uniqueness and Diversity:

The proposed project would not cause a change in the cultural uniqueness and diversity of the area because the land is currently used as a petroleum refinery; therefore, the land use would not be changing. The use of the surrounding area would not change as a result of this project.

C. Local and State Tax Base and Tax Revenue:

The refinery's overall capacity would not change as a result of the permitting action. In addition, no new employees would be needed for this project. Therefore, no impacts to the local and state tax base and tax revenue are anticipated from this project.

D. Agricultural or Industrial Production:

The permitting action would not result in a reduction of available acreage or productivity of any agricultural land; therefore, agricultural production would not be affected. The refinery's overall capacity would not change as a result of the permitting action. Therefore, industrial production would not be affected.

E. Human Health:

As described in Section 7.F of this EA, the impacts from this facility on human health would be minor because the emissions from the facility would increase, but not significantly from prior levels. The air quality permit for this facility would incorporate conditions to ensure that the facility would be operated in compliance with all applicable

rules and standards. These rules and standards are designed to be protective of human health.

F. Access to and Quality of Recreational and Wilderness Activities:

The proposed project would not have an impact on recreational or wilderness activities because the site is far 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.

G. Quantity and Distribution of Employment:

No change in the number of employees currently onsite would be anticipated as a result of the proposed project. Therefore, the action would not have any impacts to the quantity and distribution of employment at the facility.

H. Distribution of Population:

This permitting action does not involve any significant physical or operational change that would affect the location, distribution, density, or growth rate of the human population. The distribution of population would not change as a result of this action.

I. Demands of Government Services:

The demands on government services would experience a minor impact. The primary demand on government services would be the acquisition of the appropriate permits by the facility and compliance verification with those permits.

J. Industrial and Commercial Activity:

The refinery's overall capacity would not change as a result of the proposed permitting action. Therefore, no impacts on industrial activity at CHS would be expected. Industrial and commercial activity in the neighboring area is not anticipated to be affected by issuing MAQP #1821-23.

K. Locally Adopted Environmental Plans and Goals:

This permitting action would not affect any locally adopted environmental plans or goals. CHS must continue to comply with the SIP and FIP and associated stipulations for the Billings/Laurel area. The Department is not aware of any locally adopted environmental plans and goals that would be impacted by this action.

L. Cumulative and Secondary Impacts:

Overall, any cumulative and secondary impacts from this project on the social and economic aspects of the human environment would be minor. The project is associated with an existing facility and would not change the culture or character of the area. Additionally, overall emissions will remain within the facility-wide emissions caps established in MAQP #1821-05 in 2000.

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, Permitting and Compliance Division - Air Resources Management Bureau.

EA Prepared By: Skye Hatten

Date: November 30, 2010