Montana Department of
ENVIRONMENTAL QUALITY

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November 19, 2014

Patrick B. Kimmet
CHS Inc.
Laurel Refinery
PO Box 909
Laurel, MT 59044-0909

Dear Mr. Kimmet:

Montana Air Quality Permit #1821-33 is deemed final as of November 19, 2014, by the Department of Environmental Quality (Department). This permit is for CHS Inc's Laurel Petroleum Refinery. All conditions of the Department's Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

For the Department,

Julie A. Merkel
Air Permitting Supervisor
Air Resources Management Bureau
(406) 444-3626

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

JM:SJ
Enclosure

Montana Department of Environmental Quality
Permitting and Compliance Division

Montana Air Quality Permit #1821-33

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

November 19, 2014

Montana Air Quality Permit

Issued to:	CHS Inc. Laurel Refinery P.O. Box 909 Laurel, MT 59044-0909	MAQP: #1821-33 Application Complete: 8/27/2014 Preliminary Determination (PD) Issued: 9/11/2014 Department Decision (DD) Issued: 11/3/2014 Permit Final: 11/19/2014 Appeal Ends: 12/3/2014 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, 213, and 215, Montana Code Annotated (MCA), as amended, and the Administrative Rules of Montana (ARM) 17.8.740, *et seq*., as amended, for the following:

Section I: Permitted Facilities

A. Plant Location/Description

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

Section II.	Refinery Limitations and Conditions associated with MAQP #1821-05
Section III.	Fuel Gas & Fuel Oil Combustion Devices
Section IV.	Mild Hydrocracker with associated Zone D sulfur recovery unit (SRU) and tail gas treatment unit (TGTU)
Section V.	Boiler #10
Section VI.	Truck Loading Rack(s) and Vapor Combustion Unit(s) (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 and Railcar Gasoline Component Unloading

Section XIV. Boiler #12

Section XV. Benzene Reduction Unit

Section XVI. Product Storage Tanks

Section XVII. Product Storage Tank 133

Section XVIII. Wastewater Facilities

Section XIX. Intermediate Storage Tank 146

Section XX. New Main Refinery Flare / Waste Gas Control System

Section XXI. Sour Water Stripper Ammonia Combustor

Section XXII. General Conditions

B. Current Permit Action

On July 31, 2014, the Department of Environmental Quality – Air Resources Management Bureau (Department) received from CHS an application for replacement of the main refinery flare. The current flare is reaching the end of its mechanical life, and must be replaced. The replacement flare will be subject to New Source Performance Standards (NSPS) Subpart Ja (40 CFR 60 Subpart Ja), as well as 40 CFR 60.18 (Control Device and Work Practice Standards) and 40 CFR 63.11 (Control Device and Work Practice Requirements). Proposed as part of the main flare replacement project, is installation of a flare gas treatment and recovery system. Vent gases captured in the recovery system will be directed to amine treatment for removal of reduced sulfur compounds and returned to the refinery fuel gas system to be burned in fuel gas combustion units (displacing natural gas usage). During times when the amount of captured vent gases exceeds the flare gas recovery system capacity, the gases would pass through the liquid seal of the flare for destruction of the gas by combustion in the flare. Combustion of these gases is necessary to destroy the various components which would otherwise have potential to be emitted in amounts which would pose serious threat to human health and the environment.

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

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

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

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

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

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

    a. #1 Crude heater
    b. Crude Preheater
    c. #1 Crude Vacuum Heater
    d. #2 Crude Heater
    e. #2 Crude Vacuum Heater
    f. Alkylation Unit Hot Oil Belt Heater
    g. Platformer Heater (P-HTR-1)
    h. Platformer Debutanizer Heater
    i. FCC Feed Preheater (this heater will be shut down as part of the MHC project MAQP 1821-23. A replacement heater has been permitted and constructed but is not included as part of these site-wide limits
    j. #1 Naptha Unifiner charge heater (renamed NHT Reboiler Heater #2 – H-8303 for new service as part of coker project in 1821-13).
    k. #2 NU heater (shutdown as part of coker project – MAQP 1821-09)
    l. MDU Charge Heater (H-8301) (Shutdown as part of ULSD project = MAQP 1821-09) [Now not part of PAL]
    m. MDU Stripper Heater (Shutdown as part of ULSD project – MAQP 1821-09)

n. PDA Heater (shutdown as part of coker project, MAQP #1821-13)
o. #1 Road Oil/Asphalt Loading heater (asphalt loading heater #1)
p. #2 road oil heater (removed from service and now not part of the PAL)
q. BP2 Heater (the heater has been removed but the BP2 tank is still present)
r. 60 Tank Heater
s. #1 Fuel Can Heater (#1 fuel oil heater)
t. #3 Boiler (permanently shutdown as Consent Decree project; MAQP #1821-15. Has been removed.)
u. #4 Boiler (permanently shutdown as Consent Decree project; MAQP 1821-22. Has been removed.)
v. #5 Boiler (permanently shutdown as Consent Decree project; MAQP 1821-22. Has been removed.)
w. #9 Boiler
x. CO Boiler (permanently shutdown as Consent Decree project; MAQP 1821-15. Has been removed.)
y. #10 Boiler
z. H-101 Zone D Hydrogen Plant Reformer Heater
aa. H-201 Reactor Charge Heater
bb. H-202 Fractionator Feed Heater
cc. C-201B (Permanently shutdown and replaced with electric)
dd. NU Splitter Heater (renamed NHT Splitter Reboiler H-8304, MAQP 1821-13)
ee. #1 NU Stripper Heater (renamed NHT Reboiler Heater #1 H-8302, MAQP 1821-13)

2. Fuel oil-fired external combustion sources, includes:

   a. #3 Boiler (permanently shutdown as Consent Decree Project; MAQP #1821-15. Has been removed)
   b. #4 Boiler (permanently shutdown as Consent Decree Project; MAQP #1821-22. Has been removed)
   c. #5 Boiler (permanently shutdown as Consent Decree Project: MAQP #1821-22. Has been removed)
   d. #1 crude heater (ceased burning oil)

3. Gas-fired internal combustion source, includes:

   a. Platformer recycle turbine
   b. #1-4 unifier compressors (shutdown with ULSD and coker projects)

4. FCC unit (FCCU) Regenerator;

5. Zone A Sulfur Recovery Unit (SRU) Tail Gas Incinerator (TGI, SRU-AUX-4);

6. Zone D SRU Incinerator;

7. Fugitive equipment leaks include all equipment, as defined in 40 Code of Federal Regulations (CFR) 60, Subpart VV, in hydrocarbon service;

8. Wastewater sewers, separation, and treatment facilities;

9. Cooling tower sources: #1 cooling tower (CT), #2 CT, #3 CT, #5 CT;

10. Loading facilities:

    a. light product truck rack and vapor combustion unit (VCU) [excludes new facility permitted with 1821-27]
    b. heavy oil truck rack, and
    c. heavy oil rail rack;

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

A. National Emission Standards for Hazardous Air Pollutants

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

B. Annual Emission Limitations (ARM 17.8.749):

1. SO_2 emissions shall not exceed 2,980.3 tons per year (TPY)

2. NO_x emissions shall not exceed 999.4 TPY

3. CO emissions shall not exceed 678.2 TPY

4. Volatile organic compounds (VOC) emissions shall not exceed 1,967.5 TPY

5. Particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) emissions shall not exceed 152.2 TPY

6. Particulate matter (PM) emissions shall not exceed 162.2 TPY

C. Compliance Determination (ARM 17.8.749):

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

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

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

D. Reporting and Recordkeeping Requirements (ARM 17.8.749):

CHS shall provide quarterly 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 with the exception to those subject to NSPS Subpart Ja. Applicability of NSPS Subpart Ja to fuel gas combustion devices is identified on a source by source basis within the permit.

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

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

C. Limitations on Fuel Gas and Fuel Oil Combustion Devices

1. SO_2 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 H_2S per dry standard cubic foot (162 parts per million, volumetric dry (ppm_{vd}) H_2S) 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 H_2S per dry standard cubic foot (81 ppm_{vd} H_2S) per 12-month average (ARM 17.8.340 and ARM 17.8.749).

5. The burning of sour water stripper overhead (SWSOH) in any fuel gas combustion device is prohibited (ARM 17.8.749).

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

D. Monitoring Requirements

1. CHS shall install and operate the following Continuous Emissions Monitoring System (CEMS) / Continuous emission rate monitor system (CERMS): Continuous concentration (dry basis) monitoring of H_2S 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, Subpart J, 60.100-108, Subpart Ja, 60.100a-108a and Appendix B, Performance Specification 7 and Appendix F (Quality Assurance/Quality Control) provisions.

3. H_2S refinery fuel gas CEMS and fuel gas flow rate meters shall comply with all applicable requirements of the Billings/Laurel SO_2 State Implementation Plan (SIP) Emission Control Plan, including Exhibit A and Attachments, adopted by the Board of Environmental Review, June 12, 1998, and stipulated to by Cenex Harvest States Cooperative and its successor CHS.

4. Fuel oil metering and analysis specifications (SOP SIP Method C-1) shall comply with all applicable requirements of the Billings/Laurel SO_2 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 SO_2 and H_2S limits for the fuel gas-fired units within the refinery shall be based upon CEMs data utilized for H_2S, 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 SO_2 limits.

2. Compliance determinations for the SO_2 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 SO_2 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).

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

CHS shall submit quarterly emission reports to the Department. Emission reporting for SO_2 generated from the combustion of fuel oil and alkylation unit polymer shall consist of a daily 365-day rolling average (in TPY) 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 H_2S 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 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 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.

   5. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the Mild Hydrocracker unit.

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 Individual Sources

1. Zone D SRU Incinerator Stack (INC-401)

a. SO_2 emissions from the Zone D SRU incinerator stack shall not exceed (ARM 17.8.749):

i. 31.1 tons/rolling 12-calendar month total,

ii. 341.04 lb/day,

iii. 14.21 lb/hr, and

iv. 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 SO_2 emissions from the Zone D SRU incinerator stack (INC-401) to no more than 113.2 ppm_{vd} at 0% oxygen on a daily rolling 365 day average (ARM 17.8.749).

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. Reformer Heater Stack (H-101)

a. SO_2 emissions from H-101 shall not exceed (ARM 17.8.749):

i. 1.68 tons/rolling 12-calendar month total

ii. 2.15 lb/hr

b. NO_x emissions from H-101 shall not exceed (ARM 17.8.749):

i. 27.16 tons/rolling 12-calendar month total

ii. 6.78 lb/hr

c. CO emissions from H-101 shall not exceed (ARM 17.8.749):

i. 13.93 tons/rolling 12-calendar month total

ii. 4.51 lb/hr

d. VOC emissions from H-101 shall not exceed 0.35 tons/rolling 12-calendar month total (ARM 17.8.749).

e. CHS shall not combust fuel oil in this unit (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60, Subpart J).

3. Reformer Heater Stack (H-102)

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

b. CHS shall not burn in the H-102 Reformer Heater any fuel gas that contains H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60, Subpart Ja).

c. NO_X emissions from H-102 shall not exceed:

i. 40 ppmv (dry basis, corrected to 0 percent excess air) on a 30-day rolling average basis (40 CFR 60, Subpart Ja)

ii. 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 Ultra Low NOx Burners (ULNBs) (ARM 17.8.752).

g. CHS shall implement proper design and good combustion techniques to minimize CO, VOC, and $PM/PM_{10}/PM_{2.5}$ emissions (ARM 17.8.752).

4. Reactor Charge Heater Stack (H-201)

a. SO_2 emissions from H-201 shall not exceed (ARM 17.8.749):

i. 4.35 tons/rolling 12-calendar month total

ii. 1.99 lb/hr

b. NO_x emissions from H-201 shall not exceed (ARM 17.8.749):

i. 11.56 tons/rolling 12-calendar month total

ii. 2.90 lb/hr

c. CO emissions from H-201 shall not exceed (ARM 17.8.749):

i. 8.92 tons/rolling 12-calendar month total

ii. 2.23 lb/hr

d. VOC Emissions from H-201 shall not exceed 0.91 tons/rolling 12-calendar month total (ARM 17.8.749).

e. CHS shall not fire fuel oil in this unit (ARM 17.8.749).

5. <u>Fractionator Feed Heater Stack (H-202)</u>

a. SO_2 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. SO_2 (SO_2 SIP, 40 CFR 60 Subparts J and Ja)

b. O_2 (40 CFR 60, Subparts J and Ja)

c. Volumetric Flow Rate (SO_2 SIP)

2. CHS shall install, operate, calibrate, and maintain the following CEMS/CERMS for H-102 Reformer Heater Stack (H-102):

a. NO_X (40 CFR 60, Subpart Ja)

b. O_2 (40 CFR 60, Subpart Ja)

c. Stack Flow Rate (ARM 17.8.749)

3. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts J, 60.100-108, Subparts Ja, 60.100a-60.108a, and Appendix B, Performance Specifications 2, 3, 6, and Appendix F; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors (ARM 17.8.749).

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

F. Testing Requirements

1. The SRU Incinerator Stack (E-407 & INC-401) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for SO_2 and NO_x, and the results submitted to the Department in order to demonstrate compliance with the SO_2 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, in conjunction with annual CEMS/CERMS RATA performance testing in accordance with Appendix F (40 CFR Part 60) requirements, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x/O_2

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 IX.D.4.c and d (ARM 17.8.105 and ARM 17.8.749, 40 CFR 60, Subpart Ja).

5. The Reactor Charge Heater Stack (H-201) shall be tested every 2 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 2 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 SO_2 limits for the SRU Incinerator stack shall be based upon CEMS data utilized for SO_2 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 SO_2 from the emission rate monitor shall consist of a daily 24-hour average (ppm SO_2, corrected to 0% oxygen (O_2)) 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. SO_2 emissions shall not exceed:

a. 60 ppmv H_2S 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 O_2 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 O_2 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. SO_2 emission data from the refinery fuel gas system continuous H_2S concentration monitor required by Section III. The SO_2 emission rates shall be reported for the following averaging periods:

        i. Average lb/hr per calendar day

        ii. Total lb per calendar day

        iii. Total tons per month

    b. NO_x emission data from the CEMS, fuel gas flow rate meter, and emission factors developed from the most recent compliance source test. The NO_x emission rates shall be reported for the following averaging periods:

i. Average lb/MMBtu per calendar day

ii. Total tons per month

iii. lb/MMBtu per rolling 30-day average

iv. lb/MMBtu per rolling 365-day average

v. Daily average and maximum lb/hr

c. Source or unit operating time during the reporting period and daily, monthly, and quarterly refinery fuel gas and natural gas consumption rates.

d. Monitoring downtime that occurred during the reporting period.

e. An excess emission summary, which shall include excess emissions (lb/hr) for each pollutant identified in Section V.B.

f. Reasons for any emissions in excess of those specifically allowed in Section V.B with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

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

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

A. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements of ARM 17.8.342, as specified in 40 CFR Part 63, NESHAP for Source Categories.

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

2. Subpart CC - National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries.

3. The product loading rack and vapor combustion unit shall be operated and maintained as follows:

a. CHS's product loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from cargo tanks during gasoline product loading (ARM 17.8.342 and ARM 17.8.752).

b. CHS's collected vapors shall be routed to the VCU at all times. In the event the VCU is inoperable, CHS may continue to load distillates with a Reid vapor pressure of less than 27.6 kilopascals, provided the Department is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.749).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

i. The existing VCU stack shall be 35 feet above grade and the new VCU for the new truck loading rack shall at least 40 feet above grade (ARM 17.8.749).

B. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements, as specified in 40 CFR Part 60, NSPS for Stationary Sources. The following subparts, at a minimum, are applicable (ARM 17.8.340):

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

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

3. Subpart XX - Standards of Performance for Bulk Gasoline Terminals.

C. Emission Limitations

1. The total annual VOC emissions from the truck loading rack, VCU and associated equipment (which includes the proposed new truck loading rack, proposed new VCU and all associated storage tanks (135-143 and Additive Tanks # 1-4), the proposed propane loading rack, and any fugitives shall not exceed 39.23 TPY based on a rolling 12-calendar month total. This is total combined VOC emission limit for the applicable units listed in this Section (VI) and Section XVI (ARM 17.8.749).

2. VCU Emission Limitations

a. The total VOC emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 milligrams per liter (mg/L) of gasoline loaded (ARM 17.8.342, 40 CFR 63, Subpart CC, and ARM 17.8.752).

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

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

d. CHS shall not cause or authorize to be discharged into the atmosphere from the enclosed VCU any visible emissions that exhibit an opacity of 20% or greater over any 6 consecutive minutes (ARM 17.8.304(2)).

D. Monitoring Requirements

1. CHS shall perform the testing and monitoring procedures specified in 40 CFR §§63.425 and 63.427 of Subpart R, except §63.425(d) or §63.427(c) (ARM 17.8.342).

2. CHS shall install and operate a continuous parameter monitoring system capable of measuring temperature in the firebox or in the ductwork immediately downstream from the firebox in a position before any substantial heat exchange occurs (ARM 17.8.342 and 40 CFR 63, Subpart CC).

3. CHS shall monitor and maintain all pumps, shutoff valves, relief valves and other piping and valves associated with the gasoline loading rack as described in 40 CFR Parts 60.482-1 through 60.482-10 (ARM 17.8.340).

4. A monitoring and maintenance program, as described under 40 CFR 60, Subpart VVa, and meeting the requirements of 40 CFR 60, Subpart GGGa shall be instituted (ARM 17.8.749 and ARM 17.8.340).

E. Testing Requirements

1. CHS shall comply with all test methods and procedures as specified by Subpart R §63.425 (a) through (c), and §63.425 (e) through (h). This shall apply to, but not be limited to, the product loading rack, the vapor processing system, and all gasoline equipment located at the product loading rack.

2. The product loading rack VCU shall be tested for VOCs, and compliance demonstrated with the emission limitation contained in Section VI.C.1 and C.2 on an every 5-year basis or according to another testing/monitoring schedule as may be approved by the Department. CHS shall perform the test methods and procedures as specified in 40 CFR 63.425, Subpart R (ARM 17.8.105 and 17.8.342).

3. The product loading rack VCU shall be tested for CO and NO_x, concurrently, and compliance demonstrated with the CO and NO_X emission limitations contained in Section VI.B.3.b and c (ARM 17.8.105).

F. Operational and Emission Inventory Reporting Requirements

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

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

2. Subpart CC - CHS shall keep all records and furnish all reports to the Department as required by 40 CFR Part 63.655 of Subpart R.

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

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, applies to the No. 1 Crude Unit fugitive piping equipment in VOC service as appropriate.

B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):

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

2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (Refinery MACT I).

C. Emission Control Requirements for No. 1 Crude Unit (ARM 17.8.752):

1. The No. 1 Crude Unit shall be maintained and operated as per the Leak Detection and Repair (LDAR) Program. The LDAR program would apply to new equipment in both HAP and non-HAP VOC service in the No. 1 Crude Unit. The LDAR program would not apply to existing equipment in non-HAP service undergoing retrofit measures.

2. CHS shall monitor and maintain all pumps, shutoff valves, relief valves and other piping and valves associated (as defined above) with the No. 1 Crude Unit as described in 40 CFR 60.482-1 through 60.482-10. Records of monitoring and maintenance shall be maintained on site for a minimum of 2 years.

D. Monitoring Requirements

CHS shall monitor with the LDAR database the type and number of new fugitive VOC components added (ARM 17.8.749).

E. Operational and Emission Inventory Reporting Requirements

CHS shall comply with the recordkeeping and reporting requirements contained in 40 CFR 60, Subpart VVa (ARM 17.8.340 and 40 CFR 60, Subpart GGGa).

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

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart J - Standards of Performance for Petroleum Refineries applies to the two ULSD Unit heaters (H-901 and H-902) and the Hydrogen Plant heater (H-1001).

3. Subpart Ja - Standards of Performance for Petroleum Refineries applies to the H-1001 Reformer Heater.

4. Subpart GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the ULSD Unit and the Hydrogen Plant fugitive piping equipment in VOC service.

5. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the ULSD Unit and Hydrogen Plant process drains.

B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAP for Source Categories (ARM 17.8.342).

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

2. Subpart CC – NESHAP from Petroleum Refineries shall apply to, but not be limited to, Tank 96 when it is utilized in gasoline service.

C. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in the ULSD Unit and Hydrogen Plant (ARM 17.8.304 (2)).

D. Limitations on Individual Sources (ARM 17.8.752)

1. Reactor Charge Heater H-901

a. SO_2 emissions from H-901 shall not exceed (ARM 17.8.752):

i. 1.96 tons/rolling 12-calendar month total

ii. 0.90 lb/hr

b. NO_x emissions from H-901 shall not exceed (ARM 17.8.752):

i. 2.86 tons/rolling 12-calendar month total

ii. 0.65 lb/hr based on a 24-hour rolling average (recalculated hourly)

c. CO emissions from H-901 shall not exceed (ARM 17.8.752):

i. 11.76 tons/rolling 12-calendar month total

ii. 2.68 lb/hr based on a 24-hour rolling average (recalculated hourly)

d. VOC Emissions from H-901 shall not exceed 0.77 tons/rolling 12-calendar month total (ARM 17.8.752).

e. CHS shall not fire fuel oil in this unit (ARM 17.8.752 and ARM 17.8.749).

2. Fractionator Reboiler H-902

a. SO_2 emissions from H-902 shall not exceed (ARM 17.8.752):

i. 3.95 tons/rolling 12-calendar month total

ii. 1.80 lb/hr

b. NO_x emissions from H-902 shall not exceed (ARM 17.8.752):

i. 5.70 tons/rolling 12-calendar month total

ii. 1.30 lb/hr based on a rolling 24-hour average (recalculated hourly)

c. CO emissions from H-902 shall not exceed (ARM 17.8.752):

i. 11.01 tons/rolling 12-calendar month total

ii. 2.51 lb/hr based on a rolling 24-hour average (recalculated hourly)

d. VOC Emissions from H-902 shall not exceed 1.54 tons/rolling 12-calendar month total (ARM 17.8.752).

e. CHS shall not fire fuel oil in this unit (ARM 17.8.752 and ARM 17.8.749).

3. Reformer Heater H-1001

a. The H-1001 Reformer Heater shall be equipped with ULNBs (ARM 17.8.752).

b. All available 1000 Unit PSA purge gas (sulfur free) shall be fired in the H-1001 Reformer Heater except during periods of startup, shutdown, operational transition, or process upset (ARM 17.8.752).

c. CHS shall not burn in the H-1001 Reformer Heater any fuel gas that contains H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60, Subpart Ja).

d. NO_x emissions from H-1001 shall not exceed:

i. 40 ppmv (dry basis, corrected to 0 percent excess air) based on a 30-day rolling average (40 CFR 60, Subpart Ja).

ii. 29.4 tons per rolling 12-calendar month total (ARM 17.8.752).

iii. 7.7 lb/hr based on a rolling 24-hour average (ARM 17.8.752).

e. CO emissions from H-1001 shall not exceed (ARM 17.8.752):

i. 16.8 tons per rolling 12-calendar month total.

ii. 7.7 lb/hr during periods of startup and shutdown, based on a 24-hour rolling average.

f. CO, VOC and PM/PM_{10} emissions shall be controlled by proper design and good combustion practices (ARM 17.8.752).

g. CHS shall not fire fuel oil in this unit (ARM 17.8.752 and ARM 17.8.749).

E. Monitoring Requirements

1. CHS shall install and operate the following CEMS/CERMS for the Reactor Charge Heater H-901 and the Fractionator Reboiler H-902 within one year of finalized MAQP #1821-31 (ARM 17.8.749) :

a. NO_X/O_2

b. Volumetric flowrate monitor

2. CEMS/CERMS shall comply with Appendix B of 40 CFR 60, Performance Specifications 2, 3, and 6; and Appendix F of 40 CFR 60. The required volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1. These requirements are referenced and considered applicable to these monitors based on ARM 17.8.749.

3. CHS shall install and operate the following (CEMS/CERMS) for H-1001:

   a. NO_x/O_2 (40 CFR 60, Subpart Ja)

   b. CO (ARM 17.8.749)

   c. Volumetric flow rate monitor

4. CEMS and CERMS required for H-1001 shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subparts Ja, 60.100a-108a, and Appendix B, Performance Specifications 2, 3, 4A, and Appendix F. The required volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1.

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

6. Compliance with the Reformer Heater H-1001 NO_X and CO emission limits shall be determined using the NO_X/CO CEMs and the volumetric stack flow rate monitor (with appropriate moisture correction, determined from the annual stack test data (RATA)).

7. Compliance with the H-901 and H-902 NO_X emission limits shall be determined using the NO_X CEMs and the volumetric stack flow rate monitor (with appropriate moisture correction, determined from the annual stack test data (RATA)). Compliance with the H-901 and H-902 CO emission limits shall be determined from emissions factors generated from the annual CO testing requirement (CO testing, concurrent with NO_X testing, as required by Section VIII.F.2 and VIII.F.3).

F. Testing Requirements

1. CHS shall conduct an initial source test on the Reactor Charge Heater (H-901) and the Fractionator Reboiler (H-902) at the increased firing rate within 6 months of final issuance of MAQP #1821-31.

2. The Reactor Charge Heater (H-901) 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 of the H-901 process heater (ARM 17.8.105 and ARM 17.8.749).

3. The Fractionator Reboiler (H-902) 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 of the H-902 process heater (ARM 17.8.105 and ARM 17.8.749).

4. 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 of the H-1001 process heater , as applicable (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations (ARM 17.8.749)

1. In addition to stack testing required in Section VIII.F, compliance determinations for the NO_x limit for H-901, H-902, and H-1001 shall also be based upon monitoring data as required in Section VIII.E.

2. Compliance with the opacity limitation listed in Section VIII.C shall be determined using EPA Reference Method 9 testing by a qualified observer.

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

1. For the H-901 and H-902, CHS shall submit quarterly emission reports to the Department based on data from the installed CEMS/CERMS. Emission reporting for NO_X from the emission monitors shall consist of the maximum 24-hour rolling average (determined hourly) for each calendar day. 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:

   a. Monitoring downtime that occurred during the reporting period.

   b. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in VIII.D.1 through VIII.D.2. Excess emissions shall be calculated in the same fashion as required by 40 CFR Part 60.

   c. Compliance determinations for hourly and annual limits specifically allowed in Sections VIII.D.1 through VIII.D. Calculations shall utilize all valid data (ARM 17.8.749).

d. Reasons for any emissions in excess of those specifically allowed in Sections VIII.D.1 through VIII.D.2 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

2. For the H-901 and H-902, CHS shall submit quarterly emission reports to the Department for CO. CO emissions shall be determined from emission factors developed from the most recent compliance source test. The emissions factors shall be based on fuel usage (either standard cubic feet of fuel or amount of heat input). The CO emission rates shall be reported as follows:

a. The highest 24 hour rolling average (recalculated hourly) lb/hr emissions rate for each calendar day.

b. 12 month rolling sum calculated each calendar month.

3. For the H-1001, CHS shall submit quarterly emission reports to the Department based on data from the installed CEMS/CERMS. Emission reporting for NO_x and CO from the emission monitors shall consist of a daily maximum 1-hour average (ppm) for each calendar day. 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:

a. The daily and monthly NO_X averages in ppm, corrected to 0% O_2.

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 VIII.D.3 through VIII.D.4.

d. Compliance determinations for hourly, 30-day, and annual limits specifically allowed in Sections VIII.D.3 through VIII.D.4 (ARM 17.8.749).

e. Reasons for any emissions in excess of those specifically allowed in Sections VIII.D.3 through VIII.D.4 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. SO_2 emissions from the SRU-AUX-4 stack shall not exceed:

a. 250 ppm, rolling 12-hour average corrected to 0% oxygen, on a dry basis (ARM 17.8.749 and 40 CFR Part 60, Subpart J)

b. 200 ppm, rolling 12-month average corrected to 0% oxygen, on a dry basis (ARM 17.8.752)

c. 40.66 tons/rolling 12-month total

d. 11.60 lb/hr

e. 278.40 lb/day

2. CHS shall operate and maintain the TGTU on the Zone A SRU to limit SO_2 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:

a. SO_2 (40 CFR 60, Subpart J and Billings SO_2 SIP)

b. O_2 (40 CFR 60, Subpart J)

c. Volumetric Flow Rate (Billings SO_2 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 SO_2, 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 SO_2 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 SO_2 limits for the SRU-AUX-4 Stack shall be based upon CEMS data utilized for SO_2 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 SO_2 from the emission rate monitors shall consist of a daily 24-hour average concentration (ppm SO_2, corrected to 0% O_2) 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 SO_2, CO, and PM.

3. Subpart Ja—Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (The FCCU Regenerator Stack is subject to NSPS Subpart Ja for CO only, and the new FCCU Charge Heater (FCC-Heater-NEW) is subject to the fuel gas combustion device and process heater requirements).

B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):

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

2. Subpart CC – Refinery MACT I shall apply to, but not be limited to, certain parts of the FCCU piping.

3. Subpart UUU – Refinery MACT II shall apply to, but not be limited to, the FCCU.

C. Opacity

1. CHS shall not cause or authorize emissions to be discharged from the FCCU Regenerator Stack into the outdoor atmosphere that exhibit an opacity greater than 30%, except for one six-minute average opacity reading in any one hour period (ARM 17.8.304, ARM 17.8.340, 40 CFR Part 60, Subpart J).

2. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from the FCC-Heater-1 installed on or before November 23, 1968, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes (ARM 17.8.304). During the building of new fires, cleaning of grates, or soot blowing, the provisions of ARM 17.8.304(1) and (2) shall apply, except that a maximum average opacity of 60% is permissible for not more than one 4-minute period in any 60 consecutive minutes. Such a 4-minute period means any 4 consecutive minutes (ARM 17.8.304(3)).

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

D. Limitations on Individual Emitting Units

1. FCCU Regenerator Stack

a. CO emissions from the FCCU Regenerator Stack shall not exceed 500 ppmv, dry basis corrected to 0% excess air, on an hourly average basis (ARM 17.8.340, 40 CFR Part 60, Subpart Ja, and ARM 17.8.752).

b. CO emissions from the FCCU Regenerator Stack shall not exceed 100 ppm_{vd} at 0% O_2, on a 365-day rolling average basis (ARM 17.8.749).

c. CHS shall not exceed 50 ppm SO_2 by volume (corrected to 0% O_2) on a 7-day rolling average and shall also comply with an SO_2 concentration limit of 25 ppm_{vd} at 0% O_2 on a 365-day rolling average basis (ARM 17.8.340, 40 CFR Part 60, Subpart J, and ARM 17.8.752).

d. PM emissions from the FCCU Regenerator Stack shall be controlled with an ESP. PM emissions from the FCCU Regenerator Stack shall not exceed 1.0 lb PM/1,000 lb of coke burned (ARM 17.8.340, 40 CFR Part 60, Subpart J, and ARM 17.8.752).

e. NO_x emissions from the FCCU Regenerator Stack shall not exceed 65.1 ppm_{vd} at 0% oxygen on a 365-day rolling average basis. This long-term limit shall apply at all times (including during startup, shutdown, malfunction, and hydrotreater outages) that the FCCU Regenerator Stack is operating (ARM 17.8.749 and ARM 17.8.752).

f. NO_x emissions from the FCCU Regenerator Stack shall not exceed 102 ppm_{vd} at 0% oxygen on a 7-day rolling average basis. This short-term limit shall exclude periods of startup, shutdown, 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 NOx value shall be used in the average, and those periods shall be skipped in determining compliance with the 7-day and 365-day averages (ARM 17.8.749 and ARM 17.8.752).

g. NO_x emissions from the FCCU Regenerator Stack shall not exceed 117 tons per 12-month rolling average (limit is based on 65.1 ppm_{vd} at 0% oxygen on a 365-day rolling average) (ARM 17.8.749).

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

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

a. The FCC-Heater-NEW shall be equipped with ULNBs (ARM 17.8.752).

b. NOx emissions from FCC-Heater-NEW shall not exceed:

i. 40 ppmv (dry basis, corrected to 0 percent excess air) based on a 30-day rolling average (40 CFR 60, Subpart Ja and ARM 17.8.752).

ii. 10.1 tpy based on a 12-calendar month total (ARM 17.8.752).

iii. 2.6 lb/hr based on a 24-hour rolling average (ARM 17.8.752).

c. CO emissions from FCC-Heater-NEW shall not exceed 100 ppmv at 3% oxygen based on a 24-hour rolling average (ARM 17.8.752).

d. CHS shall not combust any fuel gas that contains H_2S in excess of 60 ppmv determined daily on a 365-successive calendar day rolling average basis (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60, Subpart Ja).

e. CHS shall implement proper design and good combustion techniques to minimize CO, VOC, and $PM/PM_{10}/PM_{2.5}$ emissions (ARM 17.8.752).

E. Monitoring Requirements

1. CHS shall install and operate the following CEMS/CERMS on the FCCU Regenerator Stack:

   a. CO (40 CFR 60, Subpart Ja)

   b. NO_x (ARM 17.8.749)

   c. SO_2 (40 CFR 60, Subpart J, Billings/Laurel $\underline{SO_2}$ SIP)

   d. O_2 (40 CFR 60, Subpart J, Subpart Ja, and Billings/Laurel $\underline{SO_2}$ SIP)

   e. Opacity (40 CFR 60, Subpart J, 40 CFR 63, Subpart UUU)

   f. Volumetric stack flow rate monitor (Billings/Laurel $\underline{SO_2}$ SIP)

2. CHS shall install and operate the following on the FCC-Heater-NEW:

   a. NO_X/O_2 CEMS (40 CFR 60, Subpart Ja)

   b. Volumetric stack flow rate monitor (ARM 17.8.749)

3. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts J, 60.100-108, Subparts Ja, 60.100a-108a and Appendix B, Performance Specifications 1, 2, 3, 6, and Appendix F. The volumetric flow rate monitor(s) shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1.

4. The FCCU Regenerator Stack and FCC-Heater-NEW CEMS, stack gas volumetric flow rate CEMS, and the fuel gas flow meters shall comply with all applicable requirements of the Billings/Laurel SO_2 SIP Emission Control Plan, including Exhibit A and Attachments, adopted by the Board of Environmental Review, June 12, 1998, and stipulated to by Cenex Harvest States Cooperative and its successor CHS.

5. Compliance with the emission limits in Section X.D.2aa and, X.D.2a.b shall be determined using the NO_X/O_2 CEMs and the volumetric stack flow rate monitor (with appropriate moisture correction).

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

F. Testing Requirements

1. CHS shall follow the stack protocol specified in 40 CFR 60.106(b)(2) to measure PM emissions from the FCCU Regenerator stack. CHS shall conduct the PM tests on an annual basis or on another testing schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.340, and 40 CFR 60, Subpart J).

2. The FCC Charge Heater (FCC-Heater-NEW) shall be tested annually, in conjunction with annual CEMS/CERMS RATA performance testing in accordance with Appendix F (40 CFR Part 60) requirements, or according to another testing/ monitoring schedule as may be approved by the Department, for NO_x/O_2 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.2a.b and X.D.2a.c (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations

1. Compliance determinations for the FCCU Regenerator Stack emission limits in Section X.D for NO_x, CO, and SO_2 shall be based upon monitor data, as required in Section X.E.1.

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

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

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

For the FCCU Regenerator Stack and the FCC-Heater-New, CHS shall submit quarterly emission reports to the Department based on data from the installed CEMS/CERMS. Emission reporting for SO_2 and CO (FCCU Regenerator Stack only) and NO_x from the emission monitors shall consist of a daily maximum 1-hour average (ppm) for each calendar day. 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 SO_2 concentrations (ppmv).

2. The daily and monthly NO_x averages in ppm, corrected to 0% O_2.

3. Monitoring downtime that occurred during the reporting period.

4. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section X.D.1 and X.D.2a.

5. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section X.D.1 and X.D.2a (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.

I. Notification Requirements (ARM 17.8.749)

1. 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 FCC-Heater-NEW within 15 days after the actual start-up date (ARM 17.8.340 and ARM 17.8.749).

2. 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 FCC Unit with the new Catalyst Riser within 15 days after the actual start-up date (ARM 17.8.340 and ARM 17.8.749).

3. Within 180 days from startup of the FCC-Heater-NEW, CHS shall provide documentation to the Department demonstrating that the existing FCC-Heater-1 has been permanently removed from service and has been rendered inoperable.

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. SO_2 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. SO_2 emissions from the Coker Charge Heater (H-7501) shall not exceed (ARM 17.8.752):

i. 6.61 tons/rolling 12-calendar month total

ii. 3.02 lb/hr

b. NO_x emissions from the Coker Charge Heater (H-7501) shall not exceed (ARM 17.8.752):

i. 28.2 tons/rolling 12-calendar month total

ii. 6.44 lb/hr

c. CO emissions from the Coker Charge Heater (H-7501) shall not exceed (ARM 17.8.752):

i. 400 ppm_{vd} at 3% oxygen on a 30-day rolling average

ii. 35.2 tons/rolling 12-calendar month total

iii. 8.05 lb/hr

d. During periods of startup, shutdown, and spalling (a feed heater coil decoking process completed during operation to avoid complete unit shutdown), CO emissions from the Coker Charge Heater (H-7501) shall not exceed 16.1 lb/hr on a 24-hour rolling average (ARM 17.8.752).

e. VOC Emissions from the Coker Charge Heater (H-7501) shall not exceed 1.41 tons/rolling 12-calendar month total (ARM 17.8.752).

f. CHS shall not fire fuel oil in this unit (ARM 17.8.340; 40 CFR 60, Subpart J; and ARM 17.8.752).

3. The Coker unit flare shall operate with a continuous pilot flame and a continuous pilot flame-operating device and meet applicable control device requirements of 40 CFR 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. SO_2 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 SO_2 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% CO_2 (ARM 17.8.752)

8. CHS is required to operate and maintain a mist eliminator on the Coker Cooling Tower that limits PM_{10} 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. PM_{10} 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):

<u>Zone E SRU/TGTU/TGI (Billings/Laurel SO_2 SIP)</u>

i. SO_2 (40 CFR 60, Subpart J)

ii. O_2 (40 CFR 60, Subpart J)

iii. Volumetric Flow Rate (ARM 17.8.749)

2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subparts J, 60.100-108, and Appendix B, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1 (ARM 17.8.749).

3. The Delayed Coker Unit SO_2 CEMS, stack gas volumetric flow rate CEMS, and fuel gas flow rate meters shall comply with all applicable requirements of the Billings/Laurel SO_2 SIP Emission Control Plan, including Exhibit A and Attachments, adopted by the Board of Environmental Review, June 12, 1998, and stipulated to by Cenex Harvest States Cooperative and its successor CHS (ARM 17.8.749).

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

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

F. Testing Requirements

1. The NHT Charge Heater (H-8301) shall be tested every 2 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 SO_2, 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 SO_2 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 SO_2 limits for the Zone E SRU/TGTU/TGI shall be based upon CEMS data utilized for SO_2 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 PM_{10} 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).

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

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

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 SO_2 from the emission rate monitors shall consist of a daily 24-hour average concentration (ppm SO_2, corrected to 0% O_2) 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. CHS shall include in the quarterly emissions report the VOC and PM_{10} 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. SO_2 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. O_2 (40 CFR 60, Subpart Db)

2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subpart Db; 60.40b through 60.49b, and Appendix A, Appendix B, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F.

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

4. CHS shall install and operate a volumetric stack flow rate monitor on Boiler #11. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1. The volumetric stack flow rate monitor is required within 180 days of the issuance of MAQP #1821-21 (ARM 17.8.749).

E. Testing Requirements

Boiler #11 shall be tested 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. SO_2 emission data from the refinery fuel gas system continuous H_2S concentration monitor required by Section III. The SO_2 emission rates shall be reported for the following averaging periods:

    a. Average lb/hr per calendar day

    b. Total lb per calendar day

    c. Total tons per month

2. NO_x emission data from the CEMS, fuel gas flow rate meter, and emission factors developed from the most recent compliance source test. The NO_x emission rates shall be reported for the following averaging periods:

    a. Average lb/MMBTU per calendar day

    b. Total tons per month

    c. lb/MMBTU per rolling 30-day average

3. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates.

4. Monitoring downtime that occurred during the reporting period.

5. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section XII.C.1 through 4.

6. Reasons for any emissions in excess of those specifically allowed in Section XII.C with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

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

A. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements of ARM 17.8.342, as specified in 40 CFR Part 63, NESHAP for Source Categories.

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

2. Subpart CC – Refinery MACT I shall apply to, but not be limited to, the product loading rack and VCU. The Gasoline Loading Rack provisions in Subpart CC require compliance with certain Subpart R provisions.

B. The Railcar Light Product Loading Rack and VCU shall be operated and maintained as follows:

1. CHS' railcar light product loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from railcars during gasoline product loading (ARM 17.8.342 and ARM 17.8.752).

2. CHS' collected vapors shall be routed to the VCU at all times. In the event the VCU is inoperable, CHS may continue to load distillates with a Reid vapor pressure of less than 27.6 kilopascals, provided the Department is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.749).

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

C. Railcar Gasoline Component Unloading

1. CHS shall implement proper design and operating practices while unloading gasoline components via railcars (ARM 17.8.752).

2. A monitoring and maintenance program, as described under 40 CFR 60, Subpart VVa, and meeting the requirements of 40 CFR 60, Subpart GGGa shall be instituted (ARM 17.8.340 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% CO_2 (ARM 17.8.752).

E. Monitoring and Testing Requirements

1. CHS shall perform the testing and monitoring procedures, as applicable, specified in 40 CFR 63, Subpart R (ARM 17.8.342 and 40 CFR 63, Subpart CC).

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

3. The VCU shall be initially tested for VOCs every 5 years, or according to another testing/monitoring schedule as may be approved by the Department. CHS shall perform the test methods and procedures as specified in 40 CFR 63.425, Subpart R (ARM 17.8.105 and 17.8.342).

4. The VCU shall be tested for CO and NO_x, concurrently, and compliance demonstrated with the CO and NO_x emission limitations contained in Section XIII.C.2 and 3 (ARM 17.8.105).

F. Operational and Emission Inventory Reporting Requirements (Railcar Gasoline Component Unloading)

1. CHS shall record the number of gallons of gasoline component material unloaded and the subsequent Reid vapor pressure of the material and shall report this information with the annual emissions inventory submittal (ARM 17.8.749).

2. CHS shall comply with the recordkeeping and reporting requirements contained in 40 CFR 60, Subpart VVa (ARM 17.8.749).

Section XIV: Limitations and Conditions for Boiler #12

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units applies to Boiler #12.

3. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to Boiler #12, which meets the NSPS Subpart Ja definition of a "fuel gas combustion device."

4. Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to the refinery fuel gas supply lines to Boiler #12.

B. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in Boiler #12 (ARM 17.8.304 (2)).

C. Limitations on Boiler #12

1. SO_2 emissions from Boiler #12 shall not exceed (40 CFR 60, Subpart Ja, ARM 17.8.340, ARM 17.8.752):

a. 60 ppmvd H_2S refinery fuel gas, on a rolling 365-calendar day average

b. 5.84 tons/rolling 12-calendar month total

c. 3.60 lb/hr

2. NO_x emissions from Boiler #12 shall not exceed (ARM 17.8.752):

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. O_2 (40 CFR 60, Subpart Db)

2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subpart Db 60.40b through 60.49b, Subparts Ja, 60.100a-108a, and Appendix A, Appendix B, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F (ARM 17.8.749 and ARM 17.8.342).

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

4. With exception to the initial performance test period, compliance with the lb/MMBtu limit(s) will be demonstrated using statistically significant F-factor values. The factor will be updated on a regular basis using data from all valid fuel gas samples representative of the fuel gas burned in Boiler #12. The method of compliance demonstration involving F-factor statistical significance is subject to change upon agreement with the Department and CHS (40 CFR 60, Appendix A, Reference Method 19).

5. CHS shall install and operate a volumetric stack flow rate monitor on Boiler #12 The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1 (ARM 17.8.749).

E. Testing Requirements

Boiler #12 shall be tested 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. SO_2 emission data from the refinery fuel gas system continuous H_2S concentration monitor required by Section III. The SO_2 emission rates shall be reported for the following averaging periods:

    a. Average lb/hr per calendar day

    b. Total lb per calendar day

    c. Total tons per month

2. NO_x emission data from the CEMS, fuel gas flow rate meter, and emission factors developed from the most recent compliance source test. The NO_x emission rates shall be reported for the following averaging periods:

    a. Average lb/MMBTU per calendar day

    b. Total tons per month

    c. lb/MMBTU per rolling 30-day average

    d. lb/MMBtu per rolling 365-day average

    e. Daily average and maximum lb/hr

3. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates.

4. Monitoring downtime that occurred during the reporting period.

5. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section XIV.C.1 through 4.

6. Reasons for any emissions in excess of those specifically allowed in Section XIV.C with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

Section XV: Benzene Reduction Unit

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. SO_2 emissions from the Platformer Splitter Reboiler shall not exceed:

a. 60 ppm_v H_2S 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/PM_{10} emissions from the Platformer Splitter Reboiler shall not exceed:

   a. 1.31 tons/ rolling 12-calendar month total (ARM 17.8.749)

   b. 0.30 lb/hr (ARM 17.8.752)

5. VOC emissions from the Platformer Splitter Reboiler shall not exceed 0.64 tons/rolling 12-calendar month total (ARM 17.8.752).

6. The Platformer Splitter Reboiler shall be fitted with ULNBs (ARM 17.8.752).

7. The heat input rate for the Platformer Splitter Reboiler shall not exceed 39.9 MMBtu-HHV/hr (ARM 17.8.749).

E. Limitations on Wastewater System Components

1. All new drains associated with the benzene reduction project will be routed to the sewer system that is NSPS Subpart QQQ compliant and all such drains will be treated as subject to NSPS Subpart QQQ requirements (ARM 17.8.752).

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

F. Testing Requirements

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

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

CHS shall prepare and submit a quarterly emission report within 30 days of the end of each calendar quarter. 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. SO_2 emission data from the refinery fuel gas system continuous H_2S concentration monitor required by Section III. The SO_2 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.

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

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.

B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):

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

2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tanks 135, 136, 137, 138, 142, and 143, which are classified as Group 1 storage vessels.

3. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tank 139, which is classified as a Group 2 storage vessel.

C. Limitations for Storage Tanks

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

2. Storage Tanks 135 and 136 shall each be equipped with an external floating roof and submerged fill piping (ARM 17.8.752).

3. VOC emissions from Storage Tanks 137, 138, 142, and 143 shall be controlled by the installation and use of an internal floating roof and submerged fill piping (ARM 17.8.340, 40 CFR 60, Subpart Kb, and ARM 17.8.752).

4. Storage Tank 139 shall only store #1 or #2 diesel fuel and the VOC emissions from Storage Tank 139 shall be controlled by the installation and use of a fixed roof with pressure/vacuum vents and a submerged fill piping (ARM 17.8.749).

5. Until the new loading rack and associated equipment are operational, the combined VOC emissions from Storage Tanks 135 and 136 shall not exceed 12.6 tons/rolling 12-calendar month total. This limit includes emissions while the roofs are floating and emissions during time periods that the tank roofs are landed on the legs (ARM 17.8.749).

6. The total annual VOC emissions from the truck loading rack, VCU and associated equipment (which includes the proposed new truck loading rack and proposed VCU and all associated storage tanks (135-143 and Additive Tanks # 1-4), the proposed new propane loading rack, and any associated fugitives shall not exceed 39.23 TPY based on a rolling 12-calendar month total. This is total combined VOC emission limit for the applicable units listed in Section (XVI) and Section VI (ARM 17.8.749).

7. A monitoring and maintenance program, as described under 40 CFR Part 60 VVa, and meeting the requirements of 40 CFR Part 60 GGGa shall be instituted (ARM 17.8.340 and ARM 17.8.752).

D. Monitoring Requirements

1. Combined VOC emissions from Storage Tanks 135-139, 142-143, and Additive tanks 1-4 shall be calculated and monitored utilizing the EPA TANKS software with key parameters of throughput and material properties. Tank emissions during periods the tank roofs are landed on its legs shall be calculated using appropriate AP-42 emissions equations (ARM 17.8.749).

2. CHS shall document, by month, the total VOC emissions from Storage Tanks 135-143; and Additive Tanks 1-4 and all associated fugitive sources. This must also include emissions while the roofs of the internal floating and external floating tanks are floating and emissions during time periods that the tank roofs are landed on the legs. This monthly information and the emissions relating to the operation of the new truck loading rack, VCU and all associated fugitives sources shall be used to verify compliance with the rolling 12-month limitations in Section(s) XVI.C.5, XVI.C.6, and VI.C.1.

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

CHS shall prepare and submit a quarterly emission report within 30 days of the end of each calendar quarter. 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 applicable 12-month rolling total VOC emissions, by month, as required in XVI.C.5 and XVI.C.6 and VI.C.6.

F. 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 Storage Tanks 137-143; Additive Tanks 1-4 within 15 days after the actual start-up date of each tank (ARM 17.8.340 and ARM 17.8.749).

Section XVII: Limitations and Conditions for Storage Tank 133

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart UU - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture.

B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):

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

2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tank 133, which is classified as a Group 2 storage vessel.

C. Except where 40 CFR 60, Subpart UU is applicable, CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 (2)).

D. Limitations for Storage Tank 133

1. VOC emissions from Storage Tank 133 shall not exceed 12.3 tons/rolling 12-calendar month total (ARM 17.8.749).

2. Storage Tank 133 shall be a fixed roof tank with a pressure/vacuum vent and submerged fill piping. While in asphalt and gas oil service, the tank may be heated and may be operated without the pressure/vacuum vent (ARM 17.8.752).

3. A monitoring and maintenance program, as described under 40 CFR 60, Subpart VVa, and meeting the requirements of 40 CFR60, Subpart GGGa shall be instituted (ARM 17.8.340 and ARM 17.8.752).

E. Monitoring Requirements

1. VOC emissions from Storage Tank 133 shall be calculated and monitored utilizing the EPA TANKS software with key parameters of throughput and material properties (ARM 17.8.749).

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

1. CHS shall document, by month, the total VOC emissions from Tanks 133. The monthly information shall be used to verify compliance with the rolling 12-month limitation in Section XVII.D.1. (ARM 17.8.749).

2. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each calendar quarter. 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 12-month rolling total VOC emissions, by month, for Storage Tank 133.

Section XVIII: Wastewater Facilities

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater System, shall apply to, but not be limited to:

   - Desalter Wastewater Three-Phase Separator(s)
   - API Separator(s)
   - CPI Separator(s)
   - DAF (Dissolved Air Flotation) Units

B. Limitations for Wastewater Facilities

1. The Desalter Wastewater Three Phase Separator(s) shall be equipped with a vapor collection system to return emissions from the enclosed vapor space to the process (ARM 17.8.752).

2. CHS shall equip, operate, and maintain the API Separator(s), CPI Separator(s) and the DAF Units with a vapor collection system to collect and route emissions from the enclosed vapor space to a carbon adsorption system, designed and operated to reduce VOC emissions by 95% or greater (ARM 17.8.340, ARM 17.8.752, 40 CFR 60, Subpart QQQ).

C. Monitoring Requirements

1. The concentration level of the organic compounds in the exhaust vent stream from the carbon adsorption system(s) shall be monitored on a daily basis or at intervals no greater than 20% of the design carbon replacement interval. The existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated (ARM 17.8.749).

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

1. CHS shall keep records and furnish reports to the Department as required by 40 CFR 60, Subpart QQQ, for requirements not overridden by 40 CFR 63, Subpart CC.

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

E. Notification Requirements

1. 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 Wastewater Three-Phase Separator(s), API Separator(s), CPI Separator(s), and DAF Units within 15 days after the actual start-up date (ARM 17.8.340 and ARM 17.8.749).

Section XIX: Limitations and Conditions for Intermediate Storage Tank 146

A. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):

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

2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tank 146, which is classified as a Group 2 storage vessel.

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

C. Limitations for Storage Tank 146

1. Storage Tank 146 shall be a fixed roof tank with submerged fill piping (ARM 17.8.752).

2. A monitoring and maintenance program, as described under 40 CFR 60, Subpart VVa, and meeting the requirements of 40 CFR 60, Subpart GGGa shall be instituted (ARM 17.8.340 and ARM 17.8.752).

D. Monitoring Requirements

A monitoring and maintenance program, as described under 40 CFR 60, Subpart VVa, and meeting the requirements of 40 CFR60, Subpart GGGa shall be instituted (ARM 17.8.340 and ARM 17.8.752).

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

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

Section XX: New Main Refinery Flare / New Main Waste Gas Control System (Upon startup of the New Main Refinery Flare)

A. Limitations and Standards:

1. All refinery process units and components controlled by the Main Refinery Flare in place prior to MAQP 1821-33 (Old Main Refinery Flare) shall be controlled by the New Main Refinery Flare and/or Flare Gas Treatment and Recovery System, upon startup of the New Main Refinery Flare (ARM 17.8.749).

2. Within 180 days of the initial startup of the New Main Refinery Flare and Flare Gas Recovery System, the Old Main Refinery Flare shall be made inoperable. At no time may CHS flare simultaneously from both the new and existing main refinery flare, except for any such short duration as may occur when fully switching flare gas from one main refinery flare to another (ARM 17.8.749).

3. The New Main Refinery Flare shall have a minimum stack height of 199 feet from ground level with an allowance of 2 feet of deviation. The New Main Refinery Flare shall be located as described in the MAQP #1821-33 application (ARM 17.8.749).

4. CHS shall comply with all applicable requirements of 40 CFR 60.18 and 40 CFR 63.11, including flare design, operation, and monitoring requirements (ARM 17.8.752; ARM 17.8.340 and 40 CFR 60.18; ARM 17.8.342 and 40 CFR 63.11). The New Main Refinery Flare shall be steam assisted (ARM 17.8.749).

5. The New Main Refinery Flare shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours, as determined using EPA Method 22 (ARM 17.8.752).

6. CHS shall not flare in the New Main Refinery Flare any gas exceeding 162 ppmv H_2S determined hourly on a 3-hour average basis. The combustion of process upset gases, as defined in 40 CFR 60 Subpart Ja, or fuel gas as defined in 40 CFR 60 Subpart Ja that is released to the flare as a result of relief valve leakage or other emergency malfunctions, is exempt from this limit (ARM 17.8.752).

7. CHS shall comply with all applicable requirements of 40 CFR 60 Subpart Ja, including requirements for a flare management plan, root cause analysis program, flow monitoring, and total reduced sulfur or H_2S monitoring (ARM 17.8.340 and 40 CFR 60 Subpart Ja). The flare management plan shall specifically discuss the operation and monitoring of the flare water seal and identify the associated backpressure it provides, and discuss maximizing use of the flare gas treatment and recovery system during planned maintenance events on the flare gas recovery system. The initial plan must be developed prior to, and implemented upon startup of, the New Main Refinery Flare (ARM 17.8.749 and ARM 17.8.752).

8. CHS shall install and operate a Flare Gas Treatment and Recovery System which shall be designed with at least 3 compressors, each with a capacity capable of capturing at least 45,600 scfh of vent gas, and amine treatment capacity to ensure treatment of captured vent gases to meet NSPS Ja requirements (ARM 17.8.749, ARM 17.8.752).

9. CHS shall implement a Leak Detection and Repair (LDAR) program meeting 40 CFR 60 Subpart GGGa for all new components in VOC service installed as a part of the New Main Refinery Flare project, including components added to recover and treat flare gas from the Zone E flare (Coker flare) system (ARM 17.8.752).

B. Monitoring and Recordkeeping:

1. CHS shall maintain onsite, and make available upon request, a list of all refinery process equipment and components connected to the New Main Refinery Flare (ARM 17.8.749).

2. CHS shall maintain onsite, and available at all times, the as-built design specifications of the flare and flare gas treatment and recovery system, such that a demonstration of compliance with design standards of 40 CFR 60.18 and 40 CFR 63.11, the Flare Gas Treatment and Recovery System design requirements, and the stack height requirement can be made. The records shall include manufacturer/vendor data as applicable (ARM 17.8.749).

3. CHS shall comply with applicable recordkeeping requirements of 40 CFR 60.18 and 40 CFR 63.11 (ARM 17.8.340 and 40 CFR 60.18; ARM 17.8.342 and 40 CFR 63.11)

4. CHS shall monitor compliance with the 162 ppmv H_2S flare gas limitation of Section XX.A.6 in accordance with the monitoring requirements provided in 40 CFR 60 Subpart Ja (ARM 17.8.749).

5. CHS shall comply with the monitoring and recordkeeping requirements outlined in 40 CFR 60 Subpart VVa except where specifically exempted in 40 CFR 60 Subpart GGGa (ARM 17.8.749).

C. Reporting:

1. CHS shall submit to the Department a list of all refinery process equipment and components connected to the Main Refinery Flare at the time of startup of the New Main Refinery Flare. Thereafter, CHS shall submit to the Department any updates made postmarked or emailed within 30 days of any update (ARM 17.8.749).

2. CHS shall submit the as-built design specifications and vendor/manufacturer data within six months of successful startup of the New Main Refinery Flare, with certification of truth, accuracy, and completeness made by the Responsible Official (as defined in ARM 17.8 Subchapter 12). Thereafter, CHS shall submit such information upon request (ARM 17.8.749).

3. CHS shall provide the Department written notification of the date the Old Main Refinery Flare is permanently removed from service postmarked or emailed within 15 days of the date it is permanently removed from service (ARM 17.8.749).

4. CHS shall comply with the applicable reporting requirements of 40 CFR 60 Subpart Ja (ARM 17.8.340 and 40 CFR 60 Subpart Ja).

5. CHS shall provide the Department written notification of the startup date of the New Main Refinery Flare as soon as practical, but in no case later than 5 days after the startup date of the New Main Refinery Flare, as determined by the

earlier of postmark date or email date. CHS may include in the notification such format as necessary to also fulfill the 15 day notification requirement of 40 CFR 60.7(a)(3), or, CHS may provide separate notification to fulfill this requirement (ARM 17.8.749).

6. CHS shall submit reports to the Department as outlined in the 40 CFR 60 Subpart VVa reporting requirements incorporated by reference into 40 CFR 60 Subpart GGGa (ARM 17.8.749).

7. CHS shall comply with applicable reporting requirements of 40 CFR 60.18 and 40 CFR 63.11 (ARM 17.8.340 and 40 CFR 60.18; ARM 17.8.342 and 40 CFR 63.11).

Section XXI: New Sour Water Stripper Ammonia Combustor

A. Limitations and Standards:

1. CHS shall install and operate Selective Catalytic Reduction technology on the Ammonia Combustor to achieve NO_X emissions of no more than 61 ppmv at 3% O_2 on a 365-day rolling average basis, as measured by NO_X CEMS and calculated on an each calendar day basis, applicable at all times, including startup and shutdown (ARM 17.8.752).

2. CHS shall not emit more than 1.85 lb/hr of NO_X on a rolling 24-hr average basis from the Ammonia Combustor, as measured by NO_X CEMS and stack flowrate monitor with appropriate moisture correction defined by an initial source test. The initial source test shall be completed within 180 days of startup of the ammonia combustor. This limit shall not apply during startup and shutdown of the unit when the SCR is not at its design operating temperature (ARM 17.8.749).

3. Ammonia emissions from the Ammonia Combustor shall not exceed 10 ppmv at 3% O_2 (ARM 17.8.752).

4. CHS shall not emit from the Ammonia Combustor SO_2 in excess of the following, as measured by SO_2 CEMS (ARM 17.8.752):

   a. 20 ppmv on a dry basis, corrected to 0% excess air, determined hourly on a 3-hour rolling average basis, and;

   b. SO_2 in excess of 8 ppmv on a dry basis, corrected to 0% excess air, determined daily on a 365 successive calendar day rolling average basis.

5. CHS shall not emit from the Ammonia Combustor SO_2 in excess of 0.80 lb/hr (ARM 17.8.749).

6. CHS shall comply with all applicable requirements of 40 CFR 60 Subpart Ja (ARM 17.8.340 and 40 CFR 60 Subpart Ja).

7. The Ammonia Combustor shall be operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours as determined by visual survey (ARM 17.8.752).

B. Monitoring and Recordkeeping:

1. CHS shall monitor compliance with the SO_2 emissions limitations of Section XXI.4 according to 40 CFR 60.8 and 40 CFR 60.104a, and 40 CFR 60.107a, and as otherwise described in 40 CFR 60 Subpart Ja. CHS shall comply with all applicable monitoring and recordkeeping requirements of 40 CFR 60 Subpart Ja (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja).

2. CHS shall maintain records demonstrating initial tuning of the SCR technology to minimize ammonia slip, and catalyst replacement frequency and amount. CHS shall perform source testing utilizing methodology as agreed in writing by CHS and the Department, on an every four year basis (ARM 17.8.749).

C. Reporting:

1. CHS shall notify the Department of the startup date of the Ammonia Combustor, postmarked or emailed within 15 days of the startup date (ARM 17.8.749).

2. CHS shall submit to the Department visible emissions observations semiannually, except that any observations indicating an exceedance of opacity limitations shall be reported promptly to the Department (ARM 17.8.749).

3. CHS shall report SO_2 emissions in accord with 40 CFR 60 Subpart Ja. CHS shall comply with all applicable reporting requirements of 40 CFR 60 Subpart Ja (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja).

Section XXII: General Conditions

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

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

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

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

F. 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.

G. 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.

H. Duration of Permit - Construction or installation must begin or contractual obligations entered into that would constitute substantial loss within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall expire (ARM 17.8.762).

I. Permit Fees - Pursuant to Section 75-2-220, MCA, as amended by the 1991 Legislature, failure to pay the annual operation fee by CHS may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

ATTACHMENT A

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

1. Gas fired external combustion

   a. SO_2

      i. Calculation Basis: AP-42 Section 1-4 (7/98 revision) and complete conversion of fuel gas H_2S to SO_2.

      ii. Key Parameters: Monthly fuel use (scf) per combustion unit and refinery fuel gas H_2S content from CEMS.

   b. NO_x, CO, PM_{10}/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. SO_2

      i. Calculation Basis: Methodology required in the Billings-Laurel SO_2 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. SO_2

      i. Calculation Basis: AP-42 Section 1-4 (7/98 revision) and complete conversion of fuel gas H_2S to $so_{2.}$

      ii. Key Parameters: Monthly fuel use (scf) per combustion unit and fuel gas H_2S 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. PM_{10}/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. SO_2: Calculation Basis: CEMS data and methodology required in the Billings/Laurel SO_2 SIP

b. NO_x

i. Calculation Basis: NO_x and O_2 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 O_2 CEMS, Emission factors based on annual stack tests.

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

d. PM_{10}/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. SO_2, NO_x, CO, PM_{10}/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. SO_2

i. Calculation Basis: Complete conversion of fuel gas H_2S to SO_2.

ii. Key Parameters: Monthly fuel use (scf) per combustion unit and refinery fuel gas H_2S content from CEMS.

b. NO_x

i. Calculation Basis: NO_x and O_2 CEMS, Volumetric stack flow rate monitor, Emission factors based on stack tests.

ii. Key Parameters: NO_x and O_2 CEMS, Reference Method 19, NO_x stack tests, monthly fuel use (scf), volumetric stack flow rate.

c. CO

i. Calculation Basis: CO and O_2 CEMS, Emission factors based on stack tests.

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

d. PM_{10}/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. SO_2

Calculation Basis: CEMS data and methodology required in CHS Consent Decree, NSPS Subpart J, and the Billings/Laurel SO_2 SIP.

b. NO_x

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

c. CO

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

d. PM_{10}/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. SO_2: Calculation Basis: CEMS data and methodology required in Billings/Laurel SO_2 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, PM_{10}/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. SO_2: Calculation Basis: CEMS data and methodology required in Billings/Laurel SO_2 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, PM_{10}/PM, VOC: Not applicable – not a significant source

10. Zone E SRU Incinerator

a. SO_2: Calculation Basis: CEMS data and methodology required in Billings/Laurel SO_2 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, PM_{10}/PM, VOC: Not applicable – not a significant source

11. Wastewater

a. SO_2, NO_x, CO, PM_{10}/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. SO_2, NO_x, CO: Not applicable – not a source

b. PM_{10}/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. SO_2: 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. PM_{10}/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. SO_2, NO_x, CO, PM_{10}/PM: Not applicable – not a source

   b. VOC

      i. Calculation Basis: actual emission, EPA TANKS4.0, AP-42 and other reasonable sources as outlined in the application for MAQP #1821-27.

      ii. Key Parameters: Monthly volume of material throughput from yield accounting, material property data (VP, MW, etc.).

Montana Air Quality Permit (MAQP) Analysis
CHS Inc. – Laurel Refinery
MAQP #1821-33

I. Introduction/Process Description

A. Site Location/Description

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

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

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

   a. #1 crude heater, crude preheater, #1 crude vacuum heater

   b. #2 crude heater, #2 crude vacuum heater

   c. Alkylation Unit hot oil belt heater

   d. Platformer Heater (P-HTR-1), platformer debutanizer heater

   e. Fluid Catalytic Cracking (FCC) Charge Heater (FCC-Heater-1) (Replaced with FCC-Charge Heater (FCC-Heater NEW)

   f. NHT Reboiler Heater #1 (H-8302), NHT Reboiler Heater #2 (H-8303), and NHT Splitter Reboiler (H-8304), #2 NU Heater (shutdown as part of MAQP #1821-13), MDU Stripper Heater (Shutdown as a part of MAQP #1821-09 and modified and re-permitted as part of MAQP #1821-13, Currently Naphtha Hydrotreater (NHT) Charge Heater (H-8301)), PDA Heater (Shutdown as a part of MAQP #1821-13)

   g. Zone D Hydrogen Plant Reformer Heater (H-101), Reactor Charge Heater (H-201), Fractionator Feed Heater (H-202)

   h. Asphalt Loading Heater #1

   i. #1 fuel oil heater, #60 tank heater

   j. Boiler #9, Boiler #10, Boiler #11, and Boiler #12 (Boilers #11 and #12 were replacement boilers following shutdown and removal of #3, #4, and #5 boilers)

2. Fuel oil-fired external combustion sources, includes: #3 boiler (Shutdown and removed as part of MAQP #1821-15), #4 boiler (Shutdown and removed as part of MAQP #1821-22), #5 boiler (#5 boiler shutdown and removed as part of MAQP #1821-22), CO Boiler (Shutdown and removed as part of MAQP #1821-15)

3. Gas-fired internal combustion source, includes: Platformer recycle turbine, Zone D compressor gas engine (C-201B) (Shutdown as part of MAQP #1821-23), #1-4 unifier compressors (Shutdown with ULSD and coker projects);

4. FCC unit (FCCU) Regenerator;

5. Zone A Sulfur Recovery Unit (SRU) Tail Gas Incinerator (TGI, SRU-AUX-4);

6. Zone D SRU Incinerator;

7. Delayed Coker Unit: Zone E SRU/Tail Gas Incinerator Treatment Unit (TGTU)/TGI;

8. Fugitive equipment leaks include all equipment, as defined in 40 Code of Federal Regulations (CFR) 60, Subpart VV, in hydrocarbon service;

9. Wastewater facilities;

10. Cooling tower sources: #1 cooling tower (CT), #2 CT, #3 CT, and #5 CT;

11. Loading facilities: light product truck rack and vapor combustion unit (VCU), heavy oil truck rack, and heavy oil rail rack; and

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

B. Permit History

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

The hydrodesulfurization (HDS) process is utilized to pretreat Fluid Catalytic Cracking Unit (FCCU) feeds by removing metal, nitrogen, and sulfur compounds from these feeds. The proposed HDS unit also improved the quality of refinery finished products including gasoline, kerosene, and diesel fuel. The HDS project significantly improved the finished product quality by reducing the overall sulfur contents of liquid products from the Cenex Refinery. The HDS unit provided low sulfur gas-oil feedstocks for the FCCU, which resulted in major reductions of sulfur oxide emissions to the atmosphere. However, only a minor quantity of the proposed sulfur dioxide (SO_2) 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 SO_2 and nitrogen oxides (NO_x). The application referred to significant SO_2 emission reductions, which were expected by addition of the HDS project. These anticipated major SO_2 reductions were not committed to by Cenex under federally enforceable permit conditions and limitations. The contemporaneous emissions decrease for SO_2 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 SO_2 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 SO_2 emission limits could not be removed, the limits should be corrected to allow for the combustion of natural gas and propane. The Department of Environmental Quality (Department) has altered the permit to allow for burning odorized propane in the C-201B compressor.

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

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

The following emission limitations were modified by this permit.

Source	Pollutant	Previous Limit	New Limit
SRU Incinerator stack (E-407 & INC-401)	SO_2	291.36 lb/day	341.04 lb/day
	NO_x	2.1 ton/yr 11.52 lb/day 0.48 lb/hr	3.5 ton/yr 19.2 lb/day 0.8 lb/hr
Compressor (C201-B)	NO_x	18.42 ton/yr	30.42 ton/yr
		6.26 lb/hr	7.14 lb/hr
	CO	16.45 ton/yr	68.6 ton/yr
		5.15 lb/hr - when on natural gas	6.4 lb/hr - when on natural gas
	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

Source	Pollutant	Previous Limit	New Limit
		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
Old Sour Water Stripper	SO_2	304.2 ton/yr	290.9 ton/yr
	NO_x	125.7 ton/yr	107.9 ton/yr

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

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

It has been determined that the emission and operational rates proposed during the original permitting of the HDS unit were incorrect and should have been at the levels Cenex is now proposing. Because of this, the current action and the original permitting of the HDS must be considered one project in order to determine the permitting requirements. When combined with the original permitting of the HDS, the emission increases of NO_x and SO_2 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 SO_2 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 SO_2 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 (PM_{10}) 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 PM_{10} 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 SO_2 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 SO_2 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 Trimethlypentane
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 SO_2, NO_x, CO, PM_{10}, 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 SO_2 annual emissions cap was calculated as follows:

Average refinery-wide SO_2 emissions in the period of April 1998 through 2000 added to the PSD/NAA significance level for SO_2 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 SO_2 below 40 tons. MAQP #1821-06 replaced MAQP #1821-05.

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

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

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

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

On July 30, 2003, the Department received a complete application from CHS to modify MAQP #1821-09. The application was complete with the addition of modeling information provided to the Department on August 22, 2003. CHS requested to add a new TGTU and associated equipment for Zone A's SRU #1 and SRU #2 trains to control and reduce SO_2 emissions from this source. CHS submitted modeling to the Department for a determination of a minimum stack height for the existing SRU #1 and SRU #2 tail gas incinerator stack. CHS also submitted a letter to the Department to change the name on the permit from Cenex to CHS. The permit action added the new TGTU, set a minimum stack height for the tail gas incinerator stack, and changed the name on the permit from Cenex to CHS. **MAQP #1821-10** replaced MAQP #1821-09.

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

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

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

Pollutant	Total Project PTE (TPY)	Contemporaneous Emission Changes (TPY)	Net Emissions Change (TPY)	PSD Significance Level (TPY)
NO_x	39.2	-7.5	31.8	40
VOC	-1.5	-53.3	-54.8	40
CO	106.7	-23.2	83.5	100
SO_2	39.7	0.0	39.7	40
PM	7.6	6.6	14.2	25
PM_{10}	6.7	6.6	13.3	15

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

On May 4, 2006, the Department received a complete application from CHS to incorporate the final design of three emission sources associated with the new 15,000 BPD delayed coker unit project permitted under MAQP #1821-13. The final design capacities have increased for the new NHT Charge Heater, the new Coker Charge Heater and the new Boiler No. 11. The application also includes a request to reduce the refinery-wide fuel oil burning SO_2 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 SO_2 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, PM_{10}, 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 SO_2 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 SO_2 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.[1] Due to the operational complexity of replacing two existing boilers with one new boiler in the refinery steam system, CHS requested to maintain the ability to operate the #5 Boiler for 1 year after initial start-up of Boiler #12. Combustion of fuel oil in the refinery boilers would also be eliminated primarily to generate NO_x offsets for this permitting action.

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

The application also included a request to reduce the limitation for SO_2 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 SO_2 (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 SO_2 allowed for the combustion of alkylation unit polymer in the Alkylation Unit Hot Oil Heater, the only unit that is part of the original SO_2 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

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

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.[2]

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

In addition to making the requested changes, the Department has clarified the permit language for the bulk loading rack VCU regarding the products that may be loaded in the event the VCU is inoperable and deleted all references to 40 CFR 63, Subpart DDDDD: NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters, as it was removed from the ARM in October 2008. **MAQP #1821-18** replaced MAQP #1821-17.

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

On August 13, 2009, the Department received a complete application from CHS requesting a modification to MAQP #1821-19. CHS proposed to retrofit the existing Boiler #10 with a lower NO_x control technology burner and to update the permit limits for this unit accordingly. This project was completed on a voluntary

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

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 SO_2 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 SO_2 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 PM_{10}), project related emissions increases determined under Step 1 of the required applicability analysis were below the applicable significance thresholds. For two pollutants (NOx and SO_2), 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 (NOx) burner (ULNB) design. Based on an analysis of data collected during startup and shutdown operations for Boiler #11 and Boiler #12, a short term CO limit of 23 lb/hr on a 24-hour average basis, was included for periods of boiler startup and shutdown. Additionally, CHS proposed installation and operation of a volumetric stack flow rate monitor on Boiler #11 in order to be consistent with Boilers #10 and #12.

In addition to the aforementioned updates, CHS also requested a modification to the stack testing requirements to require stack testing every 2 years as opposed to annual stack testing for the following sources: Reactor Charge Heater (H-201), Fractionator

Feed Heater (H-202), Reactor Charge Heater (H-901), Fractionator Reboiler (H-902), and NHT Charge Heater (H-8301). The Department approved this new testing schedule and MAQP #1821-21 has been updated accordingly. Additionally, various miscellaneous administrative changes were requested and included in this permitting action. **MAQP #1821-21** replaced MAQP #1821-20.

On July 27, 2010, the Department received a request to administratively amend MAQP #1821-21. The Department had inadvertently failed to modify all pertinent sections within MAQP #1821-20 to reflect the December 31, 2011 shutdown date for Boiler #4 and Boiler #5. CHS had requested the Department to administratively amend the permit to reflect this shutdown date in all applicable sections within the permit. CHS also requested the Department administratively amend the permit to include a reference to ppm_{vd} units where H_2S limits are expressed in grains per dry standard cubic feet (gr/dscf). The Department made the aforementioned administrative changes. **MAQP #1821-22** replaced MAQP #1821-21.

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

<u>"Mild Hydrocracker Project"</u>

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

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

- As a result of a significant increase in hydrogen consumption, modifications to the existing hydrogen supply and recycle system will be required. The existing C-201B gas-fired reciprocating engine and hydrogen recycle compressor will be replaced with an electric driven make-up hydrogen compressor. Additionally, a new electric-driven recycle compressor (C-203) will be added.

- The first two reactors will continue to contain a hydrotreating catalyst. The third reactor will be split from one bed of catalyst to two beds of catalyst, containing both hydrotreating and hydrocracking catalyst.

- Equipment to be added or modified as a result of volume or heat impacts include the following:

    - A hydrogen bypass line will be added to allow for hydrogen addition both upstream and downstream of the H-201 Reactor Charge Heater.

- Changes in the separation process downstream of the reactors: Two new drums will be added, Hot and Cold Low Pressure Separators, along with additional heat exchange, including two sets of process heat exchangers, one cooling water heat exchanger and one fin-fan cooler.

- Trays within the H_2S Stripper will be replaced with higher capacity trays.

- The overhead condenser and pump associated with the H_2S Stripper Overhead Drum will be modified.

- A new "wild" naphtha product draw will be added to the H_2S Stripper Overhead Drum. This stream will be processed in the Crude Unit Naphtha Stabilizer and then routed to the NHT Unit.

- A bypass line for hydrocarbon feed to the Fractionator around the H-202 Fractionator Feed Heater may be added as a result of improved heat integration.

- The trays in the Fractionator will be replaced with higher capacity trays.

- A new flow loop on the Fractionator will be added returning a portion of the diesel draw to the Fractionator. The pump will also feed the Diesel Stripper. The loop will include a new pump, a fin-fan cooler and a steam generator.

- The trays in the existing Diesel Stripper will be replaced with higher capacity trays.

- New larger pump(s) will be added on the loop between the Diesel Stripper and the Diesel Reboiler. These pump(s) may also be used for diesel product.

- The Diesel Product Cooler (fin-fan) will be replaced with a higher capacity cooler.

- New higher capacity packing will be installed in the HP Absorber. Water circulation on the absorber will be eliminated.

Within the SRU, the following physical changes were proposed:

- Replace and upgrade the acid gas burner;

- Replace the reaction furnace and upgrade to higher pressure and temperature capability;

- Replace and upgrade the waste heat boiler for higher pressure steam generation;

- Replace and upgrade the three steam reheaters;

- Upgrade the #1 sulfur condenser; and

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

Within the TGTU, the following physical changes were proposed:

- The trays in the quench tower and amine absorber will be replaced with higher vapor capacity trays;

- The cooling system will be improved through increased circulation and minor piping modifications to control the maximum temperature of the circulating amine; and

- The methyl diethanolamine amine (MDEA) used in the absorption section of the TGTU will be replaced with a proprietary high performance amine blend.

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

- A new H-102 Reformer Heater will be added to operate in parallel with the existing H-101 Reformer Heater;

- Modification of existing BFW pumps for increased capacity and a new larger condensate cooler;

- Addition of new pumps to circulate water through the steam generation coil on the new reformer heater;

- Modification of the existing steam drum internals to handle higher steam loads;

- Replace end of life trays within the deaerator tower with higher capacity trays;

- Replace the hot and cold condensate drums with upgraded internals and more corrosion resistant metallurgy;

- Replace absorbent and valves on the PSA skid; and

- Remove equipment related to the use of propane as the feed stream to the 100 Unit Hydrogen Plant.

<u>"FCCU Charge Heater-NEW"</u>

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

“ULSD Burner Fuel Project”

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

In addition to the aforementioned projects, CHS requested the Department to incorporate several administrative changes.

MAQP #1821-23 replaced MAQP #1821-22.

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

MAQP #1821-24 replaced MAQP #1821-23.

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

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

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

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

MAQP #1821-25 replaced MAQP #1821-24.

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

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

The application also included the following:

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

<u>#1 Crude Unit Revamp Project</u>

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

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

- Improvements to the preheat exchanger trains to ensure additional heat can be added to the crude oil upstream of the atmospheric column.

- Modifications to the atmospheric column from the diesel draw downward and to the associated condensing systems.

- Existing dry vacuum process will be changed to a wet vacuum system through the addition of steam.

- Redesign and replacement of the existing vacuum column.

- Installation of new equipment to recover a diesel stream from the new vacuum column.

- Addition, replacement and/or redesign of overhead and product cooling systems.

<u>Wastewater Facilities Project</u>

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

- Installation of new Three Phase Separator(s) to remove solids and free oil from wastewater generated at the crude unit desalters.

- Installation of new American Petroleum Institute (API) Separator(s) and Corrugated Plate Interceptor (CPI) Separator(s) to treat process wastewater generated at the older process units. The existing API Separator will be removed from service. As a note, emissions from the separators will be controlled with carbon canisters.

- Replacement of the existing activated sludge unit (ASU) (T-30). Replacement will be of the same size and will incorporate several design changes to improve the biological treatment efficiency.

- Installation of a second ASU and clarifier to be operated in parallel with the existing ASU and clarifier and will provide maintenance backup to the system.

- Installation of two new Sludge Handling Tanks to receive waste activated sludge from the clarifiers. The removed sludge will be dewatered and dried for offsite disposal.

- Installation of two new DAF Units to treat process wastewater from all of the process units. Emissions from the DAF Units will be controlled with carbon canisters. The existing DAF will be removed from service.

Product Blending Project

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

Additional Permit Changes

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

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

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

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

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

CHS also requested several various administrative changes and clarification additions.

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

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

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

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

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

In addition to those items mentioned above, this permit action included miscellaneous updates and amendments. CHS requested to discontinue use of the sulfur dioxide (SO_2) Continuous Emissions Monitoring System (CEMs) on the H-1001 stack because H-1001 was subject to 40 Code of Federal Regulations (CFR) 60, Subpart Ja which included exemptions from hydrogen sulfide/sulfur dioxide (H_2S/SO_2) monitoring requirements for fuel gas streams that are inherently low in sulfur content. The primary fuel to H-1001, PSA tailgas is inherently low in sulfur content. CHS already monitors the H_2S content of the refinery fuel gas (RFG) to be combusted in H-1001 as supplemental fuel, which would meet the monitoring requirements of Subpart Ja.

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

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

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

- In Section IV.A.3, CHS requested to remove 40 CFR 60, Subpart Ja from this section of the permit as the units subject to this New Source Performance Standard (NSPS) are already identified in Section X.

- In Section VI.C.1 and XVI.C.6, CHS requested that the Department remove existing gasoline and distillate loading rack and associated VCU from the VOC limit in these sections. In addition, the Department removed the notification requirement on the existing truck loading rack and associated VCU.

- Section VI.G.1.d, required notification once the existing propane loading rack has been rendered inoperable. As clarification, CHS does intend to permanently shutdown the existing propane loading rack but not the existing propane storage facilities as was previously stated in error in the CHS permit application. The Department removed the notification requirement on the existing propane loading rack. The Department understands that the propane storage facilities were not included in this action. Because the propane storage is not listed in the permit, this will not require an administrative change other than to note the clarification.

- In MAQP #1821-27, CHS proposed replacement of the burners in the H-1001 Reformer Heater. The firing rate and associated limits only apply once the heater has restarted after the retrofit. CHS requested that the Department clarify that the limits included in MAQP #1821-26 would apply until such time that the H-1001 Reformer Heater has gone through its shakedown period (CHS requested 180 days after initial startup). The Department clarified this by adding the limitations previously listed in MAQP #1821-26 back into the permit.

- The Department previously noted that there was an error in the CO limit for the H-1001 Reformer heater. As such, CHS requested that the limit in VIII.D.3.e be corrected as follows: 0.02 lb/MMBtu-HHV, or 16.8 tons per rolling 12-calendar month total.

- In Section X.D.2, CHS requested that the last sentence of the introductory paragraph be deleted as it incorrectly indicates that the conditions apply once the new FCC-Charge-Heater begins operation.

- CHS requested that Section X.D.2.a.a. be changed for consistency with the other emission limits in that that section as follows: The FCC-Heater-NEW shall be equipped with ULNB and the firing rate of the heater shall not exceed 66 MMBtu/hr-HHV based on a rolling 30-day average.

- CHS requested that Section X.G.2 and Section X.H be modified to reflect the fact that there isn't a CO CEMs on the new FCC-Heater-NEW.

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

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

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

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

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

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

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

  - *The proposed mass emission limits were derived by simply multiplying the MMBtu-based limits together;*

  - *The mass limits better accomplish the goal of restricting the short and long term emissions from the H-1001 Reformer Heater through the use of continuous concentration and flow monitors rather than determining an average of a number of grab samples; and*

  - *The mass limits are expressed in terms the CHS Operations staff has the ability to monitor in order to ensure continuous and ongoing compliance.*

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

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

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

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

- 40 CFR 60, Subpart J applicability updates: Conditions indicating NSPS Subpart J applicability to all CHS Refinery's fuel gas combustion devices were updated to reflect NSPS Subpart Ja requirements, where necessary.

- Clarification of 40 CFR 60, Subpart Ja applicability: Specific to Boiler #12, CHS requested that the MAQP be clarified to reflect that Boiler #12 meets the NSPS Subpart Ja definition of a "fuel gas combustion device" requiring compliance with the SO_2 emission limit or the H_2S in fuel gas limit.

- Railcar Light Product Loading Rack NESHAP applicability: Based on the facility's SIC code, 40 CFR 63, Subpart CC applies to the light product loading racks and 40 CFR 63, Subpart R does not apply. CHS requested clarification of this applicability within the MAQP.

- 40 CFR 60, Subpart GGGa applicability updates: The MAQP identified applicability of NSPS Subpart GGGa to refinery fuel gas supply lines to Boiler #12. However, because Boiler #12 commenced construction after November 7, 2006, it is subject to NSPS Subpart GGGa.

- 40 CFR 60, Subpart VV/VVa applicability updates: NSPS Subpart VV or VVa apply to affected facilities in the Synthetic Organic Chemical Manufacturing Industry (SOCMI). The CHS refinery is not classified as a SOCMI industry. The LDAR rules that apply to the CHS refinery include NSPS Subparts GGG and GGGa and MACT Subpart CC. Each of these rules reference specific conditions in NSPS Subpart VV and VVa, CHS proposed reference only GGG or GGGa.

- Consent Decree reference updates: Several conditions in the MAQP still contained references to the consent decree where obligations have been met. CHS requested to have these references removed.

- References to Billings/Laurel SO_2 Emissions Control Plan, as approved into the SIP: CHS requested corrections be made to the MAQP where the SO_2 SIP was referenced incorrectly.

- "plant-wide" emissions limits: Since issuance of MAQP #1821-05, inadvertently, changes have been made to the original list of emitting units to be included in these emission caps for each pollutant. Additionally, as a result of the addition and removal of various emitting units since the creation of these emission caps, the term "plant-wide" is no longer appropriate. CHS requested the list be corrected and the term "plant-wide" removed from the permit.

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

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

On August 13, 2013, the Department of Environmental Quality's Air Resources Management Bureau received from CHS an application for modification of the MAQP and the associated Title V permit to modify limits for the H-901 and H-902 process heaters.

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

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

Due to changes in the quality of crude oil and the ULSD feed, which affects the sulfur removal process, increased market demand for #1 diesel, proposed to increase emissions limits on the H-901 and H-902 heaters. The H-901 and H-902 mass rate-based emission limits were originally determined in MAQP #1821-09. These limits were based on the heat input rate of the heaters, and the emissions rate guarantee of the ultra low oxides of nitrogen (NO_X) burner design selected as BACT. The design of the burners was based on a NO_X pound per million British Thermal Units (lb/MMBtu) guarantee. In the MAQP #1821-09 application, the maximum rated heat input capacity of the heaters were presented based on the maximum expected process heat input requirements of the heaters at that time. Limitations in the form of tons per rolling twelve (12) month period and pound per hour were accepted by CHS based on the expected needs of the burners.
CHS proposed to increase the heat input component of the emission limit calculation, maintaining the Ultra-Low NO_X Burner performance on a lb/MMBtu basis, and allowing for a higher firing rate in each heater. The proposed increased NO_x, carbon monoxide (CO), and volatile organic compounds (VOC) emission limits are based on an increase in maximum heat rate input from 27.46 million

British thermal units per hour (MMBtu/hr) to 32.60 MMBtu/hr on the H-901 heater, and from 55.26 to 65.10 MMBtu/hr on the H-902 heater, on a higher heating value basis. CHS has not requested to increase allowable oxides of sulfur limits.

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

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

MAQP #1821-31 replaced MAQP# 1821-30

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

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

Additional Permit Actions. A De minimis request was also received by the Department on July 29, 2013, for piping modifications at the Railcar Light Product Loading Rack. Under the request, piping modifications were approved to allow converting loading spots that currently only allow gasoline loading to also allow diesel loading and for spots that currently only allow diesel loading to also allow gasoline loading. The MAQP did not have any language describing the piping detail of the loading spots. Since physical piping modifications were allowed under this de minimis request, this reference has been added for completeness. A De minimis request was also received by the Department on December 5, 2013, and approved on December 9, 2013. Since the de minimis request was issued prior to the end of the public comment period, this de minimis reference has been added for completeness. Under the de minimis request, the potential input of the #2 Crude Unit Vacuum Heater was lowered from 86 MMBtu-HHV/hr down to 62 MMBtu-HHV/hr. **MAQP #1821-32** replaced MAQP #1821-31.

C. Current Permit Action

On July 31, 2014, the Department of Environmental Quality – Air Resources Management Bureau (Department) received from CHS an application for replacement of the main refinery flare. The current flare is reaching the end of its mechanical life, and must be replaced. The replacement flare will be subject to New Source Performance Standards (NSPS) Subpart Ja (40 CFR 60 Subpart Ja), as well as 40 CFR 60.18 (Control Device and Work Practice Standards) and 40 CFR 63.11 (Control Device and Work Practice Requirements). Proposed as part of the main flare replacement project, is installation of a flare gas treatment and recovery system. Vent gases captured in the recovery system will be directed to amine treatment for removal of reduced sulfur compounds and returned to the refinery fuel gas system to be burned in fuel gas combustion units (displacing natural gas usage). During times when the amount of captured vent gases exceeds the flare gas recovery system capacity, the gases would pass through the liquid seal of the flare for destruction of the gas by combustion in the flare. Combustion of these gases is necessary to destroy the various components which would otherwise have potential to be emitted in amounts which would pose serious threat to human health and the environment.

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

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

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

D. Process Description – Permitted Equipment

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

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

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

Hydrogen Plant - This unit produces pure hydrogen from propane/natural gas and recycled hydrocarbon from the hydrodesulfurizer, which, in turn, is used in the HDS unit. The feed is first purified of sulfur and halide compounds by conversion over a cobalt/molybdenum catalyst and subsequent absorption removal. The purified hydrocarbon is mixed with steam and the whole stream is reformed over a nickel catalyst to produce hydrogen (H_2), CO, carbon dioxide (CO_2), and methane (CH_4). The CO is converted to CO_2 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 H_2S 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 H_2S 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. H_2S in the overhead gas from the amine still accumulator are directed to the new SRU.

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

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

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

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

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

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

The efficiency of the TGTU for sulfur removal is 99.46%. The TGTU adds additional sulfur recovery efficiency to the sulfur plant. The overall efficiency for sulfur removal for the SRU, plus TGTU, is 99.96%.

The sulfur plant incinerator (INC-401) is designed to burn any H_2S and other substances that make it past the SRU and TGTU. Also, exhaust gas from reheater E-407 (operated during Mode I) at the SRU is vented to the sulfur plant incinerator. The design heat input rate for reheater E-407 is 1.0 MMBtu/hr and is fired by natural/refinery gas. The design heat input rate for INC-401 is 3.8 MMBtu/hr. Therefore, these two fuel-burning devices, together, will fire a potential 5.0 Mscf/hr of fuel gas (4.8 total MMBtu/hr).

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

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

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

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

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

Zone A's TGTU for SRU #1 and #2 Trains - The SRUs convert H_2S from various units within the refinery into molten elemental sulfur. The SRU process consists of two parallel trains (SRU #1 and SRU #2 trains) that each include thermal and catalytic sections that convert the H_2S and SO_2 into sulfur. In each train, the process gas exits the catalytic reactors and enters a condenser where sulfur is recovered and is gravity fed into the sulfur pits. Process gas from the condensers is then sent to the TGTU for additional sulfur removal. The TGTU is an amine-type H_2S recovery and recycle TGTU. The TGTU utilizes an in-line tail gas heater (TGTU-AUX-1), which also generates hydrogen from reducing gases that reduce the SO_2 in the tail gas to H_2S. After passing through the quench tower, the stream enters an amine absorber where H_2S is selectively absorbed. The off-gas passes to the SRU-AUX-4, where it is incinerated to convert remaining H_2S to SO_2 before venting to atmosphere. The rich amine leaving the absorber is regenerated in the tail gas regenerator, and the H_2S 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 H_2S and other substances that make it past the SRU and TGTU. Also, exhaust gas from the SRU-AUX-1 is vented to SRU-AUX-4. The design heat input rate for TGTU-AUX-1 is 4.17 MMBtu/hr and the unit is fired by natural/refinery fuel gas. The design heat input rate for SRU-AUX-4 is 10.85 MMBtu/hr and the unit is fired on refinery fuel gas. Therefore, these two fuel-burning devices, together, will potentially use 18.55 Mscf/hr of natural and refinery fuel gas (15.02 total MMBtu/hr).

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

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

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

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

E. Response to Public Comments

Commenter	**Draft Permit Section**	**Comment**	**Department Response**
CHS, Inc	XX.A.1	We question the necessity of this condition. The flare is an important safety device for the refinery and, as such, connections to the flare are made to ensure a safe operating environment is maintained. Nothing with this project changes our approach for determining appropriate connections to the flare. Note that as discussed in the application there are some vent streams that will be bypassed around the FGRS because the stream characteristics are not compatible with the refinery fuel gas system.	This condition is necessary from a preconstruction permitting perspective to ensure the emitting unit remains consistent with the understandings of the Department through permit conditions. A unique part of this particular project is the flare's dependence on connections to existing and operating refinery equipment in reviewing the emissions of the unit, and also determination of what emitting unit(s) are modified. Once the project has been completed and appropriate documentation made, it may be found appropriate to remove this condition through an administrative amendment, with understanding that Draft Condition XX.B.1 would remain.

Commenter	Draft Permit Section	Comment	Department Response
CHS, Inc	XX.A.2	For clarity and consistency with previous permit actions, CHS suggests the first sentence of the condition be updated as follows: "**Within 180 days of the initial** ~~Upon successful~~ startup of the New Main Refinery Flare **and Flare Gas Recovery System**, the Old Main Refinery Flare shall be made inoperable."	The Department has incorporated the change requested. The remainder of the condition, stating that "At no time may CHS flare simultaneously from both the new and existing main refinery flare, except for any such short duration as may occur when fully switching flare gas from one main refinery flare to another" has remained.
CHS, Inc	XX.A.5	The visible emission requirement contained in this BACT condition is also included at 40 CFR 60.18. The requirement to comply with 40 CFR 60.18 is included in draft condition A.4. (also in part as a BACT condition). For this reason, condition A.5. should be removed to avoid duplicating requirements.	ARM 17.8.752 requires MT BACT review for new or modified emitting units, and includes review of visible emissions. This permit condition assigns a visible emissions limitation based on BACT (through the regulatory requirement and authority of ARM 17.8.752). However, the condition was also intentionally worded to match the requirement of 40 CFR 60.18 in efforts to streamline overlapping regulatory requirements.
CHS, Inc	XX.A.9	We suggest this BACT condition relating to the design of the system be clarified as follows: CHS shall install and operate a Flare Gas Treatment and Recovery System which shall be designed with compressor capacity and amine treatment capacity for at least 77,000 standard cubic feet per hour of vent gas." ~~on an annualized basis. All flare gas recovered shall be treated \vith the amine treater."~~	This condition was worded identically to information as presented in the application. Concerns from a compliance demonstration standpoint with the 'annualized basis' language of the condition were part of the reasoning of this comment. Therefore, the condition has been updated to reflect the following information, as presented on page 5-16 of the application. The relevant application statements used is as follows: "each compressor shall be capable of capturing 45,600 scfh of vent gas" and "..the FGRS will include three compressors - two compressors available to recover routine flow, and the third maintained as a spare *or to be used during periods of excess flare gas*". Please note, page B-1 of the application states that "CHS plans to operate two compressors at a time with the third compressor being held in reserve for a compressor trip or maintenance". The flare management plan is

Commenter	Draft Permit Section	Comment	Department Response
			expected to contain clarifying information regarding maximizing use of the flare gas recovery system at all times, including planned maintenance events. The Department would expect that information regarding capacities and abilities represented in an application be representative of what is installed.
CHS, Inc	XX.A.7, 8, 10, 11	The Department Summarized these Comments: Section 60.103a of NSPS Subpart Ja requires the refinery to develop and implement a flare management plan. CHS suggests that draft conditions A.7, A.10, and A.11 be included as part of condition A.8. rather than being stand-alone conditions. The NSPS Subpart Ja Flare Management Plan will address specific scenarios such as startup, shutdown, and maintenance scenarios where water seal level or use of the third compressor would differ from that required by these conditions.	The Department agrees the Flare Management Plan can be an acceptable place to discuss intricacies associated with different needs and scenarios and address maximizing capabilities of the flare gas treatment and recovery system during these timeframes. A clarifying statement that the flare management plan is to be implemented upon startup of the flare was made. Please note that draft condition XX.A.11 was removed from the permit to provide a more practically enforceable approach, however, the requirements of draft condition XX.A.11 stem directly from ARM 17.8.752(2). This rule states "The owner or operator of a new or modified facility or emitting unit for which a permit is required by this subchapter shall operate all equipment to provide the maximum air pollution control for which it was designed." This rule applies to CHS regardless of its absence or directly stated presence in this permit section. It is the Department's understanding that CHS intends to be able to demonstrate compliance with this rule through development and implementation of a good flare management plan.
CHS, Inc	XX.A.13	We suggest this condition be removed from the MAQP. The SO2 SIP and FIP originate from a separate regulatory program. Applicability has already been identified in the operating permit.	At CHS's request, this condition has been removed from the permit.

Commenter	Draft Permit Section	Comment	Department Response
CHS, Inc	XX.B.1, B.6, and B.7	All of these draft conditions relate to information that is required to be included in the NSPS Subpart Ja Flare Management Plan. Rather than having these individual conditions, we suggest draft condition B.4. be made more general or a general monitoring and recordkeeping condition be included: "CHS shall comply with the monitoring and record keeping requirements of 40 CFR 60 Subpart Ja."	Consistent with above comments and responses, the Department removed conditions B.6 and B.7. However, condition B.1 remains. This condition is warranted based on multiple needs identified by the Department. 1.) It serves as a compliance demonstration for condition XX.A.1. See XX.A.1 Department response. 2.) 40 CFR 60 Subpart Ja requires that the flare management plan be updated periodically to account for changes in the operation of the flare, such as new connections to the flare or the installation of a flare gas recovery system. However, NSPS Ja indicates the plan need be re-submitted to the Department only if the owner or operator adds an alternative baseline flow rate, revises an existing baseline, installs a flare gas recovery system, or is required to change flare designations and monitoring methods as described in §60.107a(g). CHS must comply with the latest approved flare management plan submitted to the Department. This permit requirement aids the Department in understanding the emitting unit, and further provides for record of CHS's approach to changes to the emitting unit which do or do not require update of the flare management plan.
CHS, Inc	XX.B.2	The records identified in this condition are included in the project design information that is maintained on site. We suggest the reference to [draft] condition A.10 be removed because it not strictly part of the equipment design and we have previously requested that A.10 be combined into a more general NSPS Ja flare management condition.	The Department has removed reference to A.10, and made other changes as necessary to provide monitoring and recordkeeping requirements with modified conditions of Section XX.A.
CHS, Inc	XX.B.3	There is a typo in this condition - 40 CFR 60.11 should be changed to 40 CFR 63.11	The Department agrees and the change requested has been incorporated

Commenter	Draft Permit Section	Comment	Department Response
CHS, Inc	XX.B.5	Similar to the comment made on draft condition A.5, this recordkeeping requirement should be removed from the permit because the visual observation requirement is already covered in condition B.3	The Department incorporated the change requested. Further, visual observations required by permit, rule, or at the request of the Department would be required to be recorded and reported per the Montana Source Test Protocol and Procedures Manual.
CHS, Inc	XX.B.8	We intend to incorporate the required LDAR monitoring for the new project components into our existing LDAR program. For this reason, we suggest this condition be streamlined, as follows: "CHS shall **comply with the monitoring and recordkeeping requirements** ~~demonstrate compliance with the standards of 40 CFR 482-1a through 40 CFR 60.482-10a within 180 days of initial startup of the New Main Refinery Flare. The demonstration shall include submission of a review of records and reports, review of performance test results, and inspections using the methods and procedures specified in 40 CFR 60.485a (ARM 17.8.749). Thereafter, CHS shall perform monitoring as~~ outlined in 40 CFR 60 Subpart VVa **except where specifically exempted in 40 CFR 60 Subpart GGGa** (ARM 17.8.749).	The Department has incorporated the changes requested.
CHS, Inc	XX.C.1	This draft condition requires submittal of a list of all refinery process equipment and components connected to the flare at the time of startup and as any additional connections are made. We believe a separate submittal of this type of information is not necessary because NSPS Subpart Ja already requires the information be included as part of the flare management plan. Additionally, NSPS Subpart Ja includes a requirement for submittal of the flare management plan.	NSPS Ja indicates the plan need be re-submitted to the Department only if the owner or operator adds an alternative baseline flow rate, revises an existing baseline, installs a flare gas recovery system, or is required to change flare designations and monitoring methods as described in §60.107a(g).
CHS, Inc	XX.C.2	This draft condition requires submittal of the as-built design specifications and vendor/manufacturer data for the new flare and flare gas recovery system along with the Responsible	The Department has maintained this requirement as a compliance demonstration method for the relevant conditions. The reporting of such information provides for a means acceptable to the

Commenter	Draft Permit Section	Comment	Department Response
		Official certification. We believe it is adequate to maintain this type of information on site and available for review as required by condition B.2. The project permit application identified the equipment to be installed and included the Responsible Official certification. Any substantive changes to the design of the equipment that would change what was represented in the application would require submittal of an updated application.	Department to demonstrate compliance with the pre-construction permit conditions, via certification of as-built design.
CHS, Inc	XX.C.3	We suggest this condition require notification of the date the existing flare is "permanently removed from service" rather than "deconstructed" because the physical removal of equipment can be stretched over a significant period of time depending on what other projects are ongoing at the refinery.	The Department has incorporated the changes requested.
CHS, Inc	XX.C.5	We suggest this condition only include the required notification of the initial startup of the new flare and flare gas recovery system rather than requirement to discuss the status and anticipated permanent shutdown (rather than "deconstruction") of the existing flare. Notification of permanent shutdown of the existing flare is required in [draft] condition C.3.	The Department has incorporated the changes requested.
CHS, Inc	XX.C.6	We suggest this condition be deleted as information related to operation and maintenance of the water seal is included as part of the NSPS Subpart Ja condition. It is our preference to not develop additional reporting requirements that overlap with existing requirements (i.e., NSPS Subpart Ja reporting) and that only deviation reporting be required for conditions such as water seal maintenance.	Due to the Department's response to earlier CHS comments regarding water seal level monitoring and inclusion as part of the flare management plan, this condition was deleted.
CHS, Inc	XXI.A.2	To meet the air quality requirements at ARM 17.8.749, a modeling demonstration was performed in support of the proposed minor modification project. The demonstration conservatively concluded that the project did not	The proposed demonstration method is acceptable, and the changes requested were incorporated. Clarification was made regarding the exclusion requested to apply during startup and shutdown scenarios (the SCR

Commenter	Draft Permit Section	Comment	Department Response
		cause or contribute to violations of the standard by comparing the modeled impacts to the significant impacts levels (SlLs). For NOx, a mass emissions rate of 1.85 lb/hr resulted in a modeled impact that was 95% of the SIL. As a result, the Department has included the NOx mass emission rate limit at Condition A.2. In accordance with Condition A.2., compliance with the NOx mass rate limit is based upon source testing performed in accordance with the Montana source testi ng protocol, which requires that testing be performed while operating at as near to full load as possible. Thus, compliance with the mass emissions rate limit would not, by design, occur during periods of cold staiiup when the SCR catalyst is below its required ammonia injection temperature. This is consistent with the fact that cold startups are infrequent and will be of limited duration, so the modeling demonstration did not consider this scenario. Condition A.I., requires CHS to install a NOx CEMS. In addition, CHS plans to install a stack flow monitor. Using the NOx CEMS, stack flow, and an appropriate moist ure correction CHS will be able to demonstrate compliance on a continuous basis rather than during source tests as envisioned by the proposed Condition A.2. For consistency with the proposed Condition A.2 the following language is proposed: "CHS shall not emit more than 1.85 lb/hr of NOx on a rolling 24-hr average from the Ammonia Combustor, as measured by NOx CEMS, stack flowrate monitor with appropriate moisture correction defined by an initial source test to be completed within 180 days of startup of the ammonia	would be expected to operate within design operating range during normal operations outside of startup or shutdown).

Commenter	Draft Permit Section	Comment	Department Response
		combustor. This limit shall not apply until the SCR reaches its design operating temperature."	
CHS, Inc	XXI.A.3	We suggest the first sentence of this condition be deleted. Demonstration of compliance with the NOx limit in condition A.1 and the ammonia slip limit in this condition ensures we are operating the SCR as intended.	The Department has incorporated the changes as requested.
CHS, Inc	XXI.A.4 and A.6	These conditions are essentially requiring the same thing. Rather than stating the A.6. requirement for two different purposes (i.e., A.4. for BACT and A.6. for NSPS Subpart Ja), we suggest that condition A.6. be deleted and a regulatory reference to NSPS Subpart Ja be added to condition A.4. Additionally, although our current intention is to comply with the NSPS Ja fuel gas combustion device S02 limits (and install a stack S02 monitor) we would like to maintain the flexibility to comply with the alternative NSPS Ja H2S in fuel gas limit instead and request condition A.4. include this flexibility.	As a new unit, this unit is subject to BACT through ARM 17.8.752. These limits were established through that authority. However, to aid in streamlining the potentially overlapping requirements, the condition was written identical to language in NSPS Ja upon determination that the NSPS provides an appropriate level of BACT. Draft condition A.6 was required to capture all other requirements of NSPS Ja. The Department cannot avoid multiple authorities for the same condition; however, a streamlined condition could meet all requirements in this scenario. Note this approach is identical to the approach taken to SO_2 emissions of the flare, and to opacity requirements of the flare.
CHS, Inc	XXI.A.5	The mass SO2 emission limit for the ammonia combustor is not needed because the NSPS Subpart Ja concentration limit in condition A.4. is more stringent. This was discussed in CHS Response #1 in our August 19 letter. We suggest this condition be removed from the permit.	This emissions limit was formed to provide for a means of limiting the potential to emit of this unit, for a pollutant of special concern. The capacity of the ammonia combustor, and therefore the PTE, has not been definable to date.
CHS, Inc	XXI.A.7	This condition identifies no visible emissions as BACT for the ammonia combustor. While we agree that visible emissions are not anticipated for this source, we feel it is appropriate that the opacity condition for this source be the emission standard identified at ARM 17.8.316(3), as follows:	The Department believes, and CHS has supported, that the 0% opacity condition is technically practicable and economically feasible for this particular emitting unit. Further, the anticipation of 0% opacity during normal operation serves as an indicator that proper operations and maintenance and burning of fuel with properties expected are

Commenter	Draft Permit Section	Comment	Department Response
		• A person may not cause or authori ze to be discharged into the outdoor atmosphere from any incinerator emissions which exhibit an opacity of 10% or greater averaged over six consecutive minutes. This is consistent with the determinations made for refinery sources subject to this rule.	present, which supports the Department decision that a testing frequency for CO, VOC, and PM is not a necessary permit condition. Further, the form of this limit provides for an easier demonstration and also a more enforceable permit condition, which does not require the level of opacity emissions to be determined.
CHS, Inc	XXI.B.1	We suggest this condition be streamlined, as follows: "CHS shall ~~monitor compliance with the SO2 emissions limitations of [Draft] Section XXI.4 according to 40 CFR 60.8 and 40 CFR 60.107a, and as otherwise described in~~ **comply with the monitoring and recordkeeping requirements in** 40 CFR 60 Subpart**s A and** Ja." ~~CHS shall comply with all applicable monitoring and recordkeeping requirements ofr 40 CFR 60 Subpart Ja."~~ Note that this streamlined language would be appropriate regardless of whether we ultimately choose to comply with the NSPS Subpart Ja H2S in fuel gas or SO2 in stack limits.	The Department incorporated the request.
CHS, Inc	XXI.B.2	To be consistent with our comment on condition A.3, this condition should only address the required testing to demonstrate compliance with the ammonia slip limit. Additionally, CHS suggest the following update regarding the ammonia slip test method: "CHS shall perform source testing ~~(using an EPA MEthod approved for use in this application if one exists, or otherwise~~ utilizing methodology as agreed in writing ~~with~~ **by** CHS and the Department. . . ."	The Department incorporated the changes as requested.
CHS, Inc	XXI.B.3	Because opacity from this source is not a significant concern, we recommend that the visible emission or opacity observation (EPA Reference Method 9) only be required as requested (i.e., rather than "no less than once per month"). There are no sources at the refinery that currently have a	At this time, to remain consistent within the permit and the majority of the source category, the Department has incorporated the change requested. The Department may request testing at any time.

Commenter	Draft Permit Section	Comment	Department Response
		requirement to complete an opacity observation at a set frequency, with the exception of the FCCU regenerator that has a COMS installed in accordance with the NSPS Subpart J requirement at 40 CFR 60.105(a)(1).	
CHS, Inc	I.B. and Permit Analysis [Draft] Page 33	We suggest the following clarifications to the Current Permit Action description: Paragraph 1: "Vent gases captured in the ~~refinery process~~ **recovery system** will be directed to amine treatment. . .." "During times when the amount of captured vent ~~gasses~~ **gases** exceeds the ~~fuel~~ **flare** gas recovery system capacity,. . ." "Combustion of these ~~gasses~~ **gases** is necessary . . ." Paragraph 2, last sentence: ". . .and waste heat in the ammonia combustor **exhaust** will be used to generate steam."	The Department incorporated the changes as requested.
CHS, Inc	Permit Analysis Page 57	In the second sentence of the first paragraph under "Main Refinery Flare and Flare Gas Treatment and Recovery System": "...especially at the potential emissions **rates** which could occur. . ."	The Department incorporated the changes as requested.
CHS, Inc	Permit Analysis Page 58	In the second paragraph, the references to "waste" gas should be clarified as "vent" gas. In the third paragraph, the first two sentences can be combined.	The Department incorporated the changes as requested.
CHS, Inc	Draft EA, Page 1	The last word in the *Description of Project* paragraph should be **combustor**	The Department agrees and has incorporated the change to reflect an ammonia combustor instead of ammonia combustion.
CHS, Inc	IV.B	In the draft permit, condition IV.B.2 that identified applicability of 40 CFR 63 Subpart ZZZZ was removed as requested becaue the C-201B compressor was permanently shutdown. The remaining part of this Section B. and B.1. can be deleted, as well.	This is likely an applicable condition for the refinery; however, the condition does not need to be listed specifically under the Mild Hydrocracker Section of the MAQP. The Department has removed the condition from this section, as requested. Please note, MACT ZZZZ may be applicable, and should be clarified in the Title V Operating Permit. Also note

Commenter	Draft Permit Section	Comment	Department Response
			that MACT ZZZZ is not shielded in the Title V.
CHS, Inc	X.F.2.	The initial source test of the FCC Charge Heater (FCC-Heater-NEW) has been completed. As such, the reference to the initial test in the first sentence of this condition can be removed.	The Department incorporated the changes as requested.
CHS, Inc	XX and XXI	For ease of implementation it is our preference that the permit be organized in a consistent manner. For consistency, each section would include the following subsections: Limitations and Conditions for the Unit or Project (I.e. NSPS applicability, etc), Limitations on Individual Emitting Units (i.e., stack resting requirements and frequency), Monitoring Requirements (i.e. CEMs), Testing Requirements (i.e., stack stesting requirements and frequency), Compliance Determinations, Reporting Requirements (i.e., things to be included in the quarterly MAQP report) and Notification Requirements (i.e., startup dates, etc). CHS would be hapy to assist in reorganization of the permit conditions.	Although the Department would be open to this request, at this time and in consultation with CHS, it seems a separate Administrative Amendment action would be best in reviewing reorganization of this section or any or all other sections of the permit.

F. Additional Information

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

II. Applicable Rules and Regulations

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

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

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

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary

equipment, including instruments and sensing devices, and shall conduct tests, emission or ambient, for such periods of time as may be necessary, using methods approved by the Department.

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 PM_{10}

CHS must comply with the applicable ambient air quality standards.

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

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

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

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

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

5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. Commencing July 1, 1971, no person shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions.

6. ARM 17.8.324 Hydrocarbon Emissions – Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.

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

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

   b. Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

   c. Subpart J - Standards of Performance for Petroleum Refineries

   d. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (The new gasoline/distillate truck loading rack VCU is subject only to the H_2S in fuel gas or SO_2 emission limit).

   e. Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

f. Subpart XX - Standards of Performance for Bulk Gasoline Terminals the construction or modification of which is commenced after December 17, 1980

g. Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture

h. Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or before November 7, 2006.

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

j. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems

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

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

b. Subpart FF – National Emissions Standards for Benzene Waste Operations.

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

a. Subpart A - General Provisions applies to all NESHAP source categories subject to a Subpart as listed below.

b. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.

c. Subpart UUU – MACT Standard for Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

d. Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

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 SO_2, NO_x, CO, VOC, and PM emissions; therefore, an air quality permit is required.

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

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

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, modification, or use of a source. CHS submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. CHS submitted an affidavit of publication of public notice for the July 29, 2014, 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, SO_2, NO_x, CO, and VOCs). The project considered in 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. Section IV. Emission Inventory of this permit summarizes the project-related emissions increases for this action.

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 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 PM_{10} in a serious PM_{10} 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 #1821-33 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 PM_{10} nonattainment area.

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

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

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

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

Based on these facts, the Department determined that CHS is a major source of emissions as defined under Title V. CHS will be required to submit a Title V Application to update the Operating Permit with this project within 12 months after commencing operation.

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

1. "Incinerator" means any single or multiple-chambered combustion device that burns combustible material, alone or with a supplemental fuel or catalytic combustion assistance, primarily for the purpose of removal, destruction, disposal, or volume reduction of all or any portion of the input material.
2. "Solid waste" means all putrescible and nonputrescible solid, semisolid, liquid, or gaseous wastes, including, but not limited to...air pollution control facilities...

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

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

Health Risk Assessment (MAQP #1821-04)

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

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

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

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

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

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

Health Risk Assessment (MAQP #1821-13)

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

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

Chemical Compound	Modeled Conc. μg/m³	Table 1* Conc.1 μg/m³	Table 2* Conc. μg/m³
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. μg/m^3	Table 1* Conc.1 μg/m^3	Table 2* Conc. μg/m^3
Carbon Disulfide	3.18E-02	--	7.00E-00
Total concentrations =	3.18E-02		

*Refers to ARM 17.8.770

The modeling demonstrated that the ambient concentrations of the carbon disulfide (the only HAP expected to be emitted), are less than the concentrations contained in Table 1 and Table 2 of ARM 17.8.770; therefore, the carbon disulfide were excluded from further review. Updated information provided to the Department on October 24, 2006, revised the modeled concentration of carbon disulfide to 3.05E-02, which did not effect this determination. Therefore, the Department determined that the health risk assessment model demonstrated negligible risk to public health in this case.

Health Risk Assessment (MAQP #1821-27)

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

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

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

Truck Loading Rack VCU - Screening Level Concentrations

Annual Average, 0.1 x One Hour Maximum VOCs **[μg/m³]** (a) =	7.055			
Chemical	**Annual Average [μg/m³]**	**Cancer Chronic(b) [μg/m³]**	**Non-Cancer Chronic(c) [μg/m³]**	**Non-Cancer Acute(c) [μg/m³]**
Benzene	6.35E-02	1.20E-02	0.71	N/A
Ethylbenzene	7.10E-03	N/A	10.0	N/A
n-Hexane	1.13E-01	N/A	2.0	N/A
Toluene	9.17E-02	N/A	4.0	N/A
m-Xylene	3.53E-02	N/A	3.0	44.0

(a) Annual Maximum concentration calculated by apply a scaling factor of 0.1, as recommended by MDEQ and EPA's Screening Procedures for Estimating the Air Quality Impact of Stationary Sources (October 1992, EPA-454/R-92-019)
(b) ARM 17.8.770, Table 1.
(c) ARM 17.8.770, Table 2.

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

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

The annual average benzene concentration was divided by its respective Reference Concentrations (RfC) to determine individual non-cancer hazard quotients. RfCs have been developed to compare effects of a theoretical exposure to a standard exposure level with known effects. They represent estimates of daily concentrations that, when exposure persists over a given period of time (generally 70 years for

3 HHRAP chapters are available at http://www.epa.gov/osw/hazard/tsd/td/combust/risk.htm#hhrad. See Chapter 7 for analyses methods.
4 See Table 1 at this EPA web site: http://www.epa.gov/ttn/atw/toxsource/summary.html.

chronic effects), adverse effects are considered unlikely. The individual hazard quotients were also summed to derive a cumulative hazard index value. Results of the cancer risk and non-cancer hazard assessments are presented below.

Calculated Risk Summary

Chemical	Annual Average Concentration (μg/m³)	EPA Risk Factors[(a)]		Calculated Cancer Risk	Calculated Non-Cancer Chronic HQ
		Cancer, Chronic (per μg/m³)	Non-Cancer Chronic HQ (μg/m³)		
Benzene	0.0635	7.80E-06	30.0	4.95E-07	2.12E-03
			Total =	4.95E-07	2.12E-03

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

ARM 17.8.740(16) defines "negligible risk to the public health, safety, and welfare and to the environment" as "an increase in excess lifetime cancer risk of less than 1.0 x10^{-6}, for any individual pollutant, and 1.0 x 10^{-5}, for the aggregate of all pollutants, and an increase in the sum of the non-cancer hazard quotients [e.g., hazard index] for all pollutants with similar toxic effects of less than 1.0, as determined by a human health risk assessment conducted according to ARM 17.8.767." As shown, the results of this analysis are all well below these regulatory threshold values.

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

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

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

Health Risk Assessment (MAQP 1821-33)

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

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

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

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

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

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

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

Table 2 above demonstrates all pollutant levels were determined to be significantly below the screening levels of ARM 17.8.770. In accord with ARM 17.8.770, there would be negligible risk to public health from the ammonia combustor emissions. Environmental effects unrelated to human health were not considered in determining compliance with the negligible risk standard, but were evaluated as required by the Montana Environmental Policy Act, in determining compliance with all applicable rules or other requirements requiring protection of public health, safety, welfare and the environment. The Montana Environmental Policy Act review is attached to MAQP #1821-33, with no significant impacts determined, based on the extremely low level of concentrations expected.

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.

Ammonia Combustor

NO_X and Ammonia (NH_3)

The purpose of the ammonia combustor is to oxidize the ammonia removed from the sour water stripping process. Because a high amount of fuel bound nitrogen is present in this process, good combustion practices alone would still provide for a relatively high amount of NO_X emissions. Add on control technologies can include Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). SCR provides a higher NO_X reduction (typically 70% - 90%) than SNCR (typically more on the order of 50% without additional combustion controls that would effectively reduce NO_X generation, as would be the case in this scenario). SCR was selected by CHS as BACT for this application, with an expected reduction of 83%.

In SCR, a metal based catalyst is used to increase the rate of the reduction reaction, which reduces NO_X into molecular nitrogen and water, with excess oxygen typically at 2 to 4 percent. Catalyst activity decreases with time. As the catalyst activity decreases, NO_X removal decreases and ammonia slip increases. When the ammonia slip reaches the maximum design or permitted level, new catalyst must be installed. According to the EPA Air Pollution Control Technology Fact Sheet for SCR, ammonia slip is typically permitted at 2 to 10 ppm. The maximum allowable ammonia emissions from the ammonia combustor has been set at 10 ppmvd @ 3% O_2.

Because CHS has proposed a NO_X removal technology representative of the highest available removal and within the typical removal efficiencies and design parameters, the Department has accepted SCR technology, with 61 ppmv @ 3% O_2 on a 365 day rolling average basis (determined daily), with Ammonia emissions not to exceed 10 ppmvd @ 3% O_2, as BACT. SCR technology requires high temperatures in order to achieve the maximum reduction rates. The long averaging time provides for applicability of this limit during all times, including periods of startup and shutdown. 'Cold startups', where the ammonia combustor begins operations without the SCR having opportunity to reach operating temperatures, results in higher emissions than those achieved during steady state operations. The Department approved the averaging time requested.

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

The uncontrolled emissions of CO, VOC, and $PM/PM_{10}/PM_{2.5}$ from combustion of ammonia would be expected to be very small. Ammonia itself does not have carbon to burn to create CO or CO_2, although the stream may have some hydrocarbon impurities in it. Natural gas is supplied as a supplemental fuel to ensure proper combustion of the ammonia stream. For emissions inventory purposes, emissions were determined assuming AP-42 factors for natural gas, applied to the total heat input of the ammonia combustor. Therefore, emissions are known to be overestimated. Although emissions would be expected from the natural gas combustion, the limited amount of emissions associated with this process dictates that add on controls would be cost prohibitive.

Opacity

With small amounts of $PM/PM_{10}/PM_{2.5}$, CO, and VOC expected, visible emissions from a properly operated ammonia combustor would be expected to not be present. Further, the presence of no visible emissions provides for some level of confidence regarding proper design, operations and maintenance to minimize PM, CO, and VOC. Therefore, the Department determined that zero visible emissions, except for any visible emissions not to exceed 5 minutes in any two hour period, constitutes an appropriate BACT condition.

SO_2 and H_2S

The Sour Water Stripper's function is to remove reduced sulfur compounds from the water. The two stage technology creates two different vent streams, one rich in reduced sulfur compounds which is to be treated at the Sulfur Recovery Units (no emissions increase proposed), and one rich in ammonia. The ammonia stream would be expected to still contain some reduced sulfur impurities, and therefore, would be treated by caustic scrubber. Because the Ammonia Combustor would be subject to the Fuel Gas Combustion requirements of 40 CFR 60 Subpart Ja, the ammonia combusted in the ammonia combustor would be required to be inherently low in reduced sulfur compounds, resulting in a small amount of SO_2 emissions. Any additional controls would be cost prohibitive.

Main Refinery Flare and Flare Gas Treatment and Recovery System

The refinery process creates waste gases which are high in hydrogen sulfide and various VOCs and HAPs. Uncontrolled release of these gases could pose serious human health and environmental consequences, especially at the potential emissions rates which could occur during malfunctions at a refinery. Refinery flares serve an important environmental and safety role by ensuring destruction of these compounds into components which pose significantly reduced threat to human health and the environment.

Although use of flares has long been accepted as an important component to air pollution control, much research in the refinery source category has occurred with interests in minimization of flaring by finding alternative uses for the gases, and use of technology which can treat flare gas to reduce the amount of sulfur compounds in the gas to minimize SO_2 emissions.

Quantifying emissions reduction opportunities from a flare is very difficult, because flare flow rates and the composition of the waste gases are highly variable, with malfunctions creating the highest potential for flare emissions. EPA has issued progressive New Source Performance Standards (NSPS), such as 40 CFR 60 Subpart Ja, which recognizes and addresses the nature of waste gases and flaring created at a refinery. For example, NSPS Ja which was promulgated in September 2012 requires that all flare gas not exceed 162 parts per million of H_2S on a volume basis. The NSPS also requires a Flare Management Plan, Root Cause Analysis Program, and flare gas flow rate monitoring. Further, the NSPS has requirements for fuel gas combustion devices, requiring that gases recovered and used in refinery process units instead of being flared meet H_2S treatment requirements.

Benefits associated with recovering waste gases for use within the refinery, instead of being flared, is the offsetting of natural gas usage in the refinery process. However, because the vent gas creation can be variable in both amounts generated and compositions of the gas, refinery fuel gas balancing can be very challenging from both a design and operations standpoint. Refineries are continually gaining better understanding of vent gas creation and usability by virtue of flare management plans, root cause analyses, and gas monitoring.

CHS has proposed flare gas treatment and recovery as part of the main flare replacement project which would take vent gases which would otherwise be flared in CHS's current operation, and instead route the gas through amine treatment to reduce H_2S concentrations in the gas, and put the treated gas into the refinery fuel gas system to be burned in process equipment.

According to CHS, the flare gas treatment and recovery system is proposed to have a capacity which can be fully utilized in current refinery fuel gas burning process units approximately 75% of the year, under normal operating conditions. A higher capacity fuel gas recovery system would likely result in refinery fuel gas balance issues, resulting in the fuel gas being flared instead of used in the process. Therefore, additional fuel gas recovery capacity would not be expected to result in a reduction of flare emissions under current operations.

<u>SO_2</u>

The New Main Refinery Flare will be subject to 40 CFR 60 Subpart Ja, which includes requirement that gas which is flared have no more than 162 ppmv H_2S. The Department determined that these H_2S concentration limits of the flare gas constitutes BACT, effective upon startup of the flare. Further, CHS has proposed flare gas recovery and treatment, which will reduce the amount of gases flared in the flare and associated SO_2 emissions. ARM 17.8.752 requires that this system be used to its full extent possible.

<u>Opacity, VOC, CO, PM</u>

Opacity is an indicator of good combustion. In practice, minimized opacity is achieved through proper air entraining and/or steam assist in the flare, with steam assisted flares being the predominant flare type found in refineries and chemical plants. Steam assisted flares inject steam into the combustion zone to promote turbulence for mixing and to induce air into the flame. This provides for a well-mixed/oxygenated gas which burns with higher efficiency. A properly designed flare with appropriate mixing, which burns gas with no less than 300 Btu/scf, is believed to be able to achieve at least a 98% destruction efficiency of the gases burned.

Therefore, Opacity can serve as a good indicator of destruction of VOC's, minimization of CO emissions with good oxygenation in the combustion, and minimized PM emissions from good combustion.

The Department determined 0% opacity from the flare, except for opacity not to exceed 5 minutes in any two hours, constitutes BACT. The Department also determined that the flare must be designed and operated such that a minimum 98% control efficiency can be claimed. Further, CHS has proposed flare gas recovery, which will reduce the amount of gases flared in the flare. ARM 17.8.752 requires that this system be used to its full extent possible.

Fugitive VOC from Equipment Leaks

VOC emissions can occur from equipment leaks from new components in VOC service. CHS proposed to implement a Leak Detection And Repair (LDAR) program meeting the requirements of NSPS Subpart GGGa as BACT. Based on review of control options and feasibility, and effectiveness and costs presented in EPA's development of NSPS GGGa, the Department accepted CHS's proposal to implement an LDAR program meeting NSPS GGGa as BACT.

NO_X

The Department is not aware of control technology for NO_X for a flare. Gas flow rates to the flare are highly variable, with high temperatures required to obtain high efficiency destruction of the gas. CHS has proposed flare gas recovery, which will reduce the amount of gases flared in the flare. ARM 17.8.752 requires that this system be used to its full extent possible.

IV. Emission Inventory

Summary of Project Related Emissions Changes in Tons Per Year						
	SO_2	NO_X	$PM/PM_{10}/PM_{2.5}$	CO	VOC	CO_2e
Flares/FGRS RFG Units[a,b]	-0.16	-18	-98	-2.0	-1.4	-30,971
Flare Pilot	0.0004	0.05	0.25	0.40	0.40	78
Ammonia Combustor	1.40	8.1	10.6	1.0	0.7	15,073
SRUs[c]	0.12	0.0	0.0	0.0	0.0	0.0
WW Drains/Junction Boxes					0.8	
Refinery Equipment					2.5	
Wastewater Treatment					0.5	

a – Reductions based on conservative estimate of displacement of natural gas burning
b – SO_2 increase based on displacing natural gas and burning refinery fuel gas (RFG) which has higher Sulfur levels
c – Based on change in utilization, assuming conservative sulfur recovery

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 (NAAQS) and for the 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 PM_{10} (respirable) standards. The Billings area is listed as not classified/attainment for the PM_{10} standard.

The area (2.0 km) around the CHS Refinery in Laurel is federally designated as nonattainment for the SO_2 NAAQS (40 CFR 81.327). Ambient air quality monitoring data for SO_2 from 1981 through 1992 recorded SO_2 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 SO_2 SIP for the Billings/Laurel area was inadequate and needed to be revised. The Department, in cooperation with the Billings/Laurel area SO_2 emitting industries, adopted a new control plan to reduce SO_2 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 SO_2 emissions have since declined between 1992 and 2008. The decline can be attributed to industrial controls added as part of the SIP/FIP requirements, NSPS requirements, plants operating at less than full capacity, and industrial process changes.

VI. Air Quality Impacts

The changes incorporated within the current permit action will not result in a significant net emissions increase with respect to PSD. The current action provides for flare gas treatment and recovery which provides for a reduction in real emissions. Further, modeling of the change in location of emissions was conducted. The Department believes this project will not cause any negative change to ambient air quality.

VII. Taking or Damaging Implication Analysis

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

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

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

VIII. Environmental Assessment

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

DEPARTMENT OF ENVIRONMENTAL QUALITY
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

Montana Air Quality Permit (MAQP) Number: 1821-33

Preliminary Determination on Permit Issued: 9/11/2014
Department Decision Issued: 11/3/2014
Permit Final: 11/19/2014

1. *Legal Description of Site*: South ½, Section 16, Township 2 South, Range 24 East in Yellowstone County.

2. *Description of Project*: CHS is proposing to replace the main refinery flare, add flare gas recovery and treatment, and replace the Zone D Sour Water Stripping process with a new two stage stripper and ammonia combustor.

3. *Objectives of Project*: The primary objectives of this permitting action would be to allow for replacement of the main refinery flare which is reaching the end of it's mechanical life.

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 BACT determinations, would be contained in MAQP #1821-33.

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 permit action would allow for minor changes in emissions of all pollutants from an existing source of these emissions. No discernible impact to terrestrial and aquatic life and habitats as a result of the changes permitted in MAQP #1821-33 would be expected. Any impacts would be expected to be minor.

B. Water Quality, Quantity, and Distribution:

This permit action would allow for minor changes in emissions of all pollutants from an existing source of these emissions. The emissions changes would not be expected to result in any discernible impact to water quality, quantity, and distribution. The new flare will be placed on previously disturbed industrial land, which is located more than a quarter mile from the river. Impacts to water quality would be expected to be minor.

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

Disturbance at the site of the new flare would occur. All disturbances would occur on the existing CHS site. Impacts to geology and soil quality, stability, and moisture would be minor.

D. Vegetation Cover, Quantity, and Quality:

This permit action would allow for minor changes in emissions of all pollutants from an existing source of these emissions. The emissions changes would not be expected to result in any discernible impact to vegetation cover, quantity, and quality. The permitting action would result in disturbances at the site of the new flare. No vegetation cover is present at the installation site. Disturbances associated with construction would be expected to be minor and short lived. The Administrative Rules of Montana (ARM 17.8.308(3) requires that no person shall operate a construction site or demolition project unless reasonable precautions are taken to control emissions of airborne particulate matter. Such emissions of airborne particulate matter from any stationary source shall not exhibit an opacity of 20% or greater averaged over six consecutive minutes. Therefore, any impacts from dust from construction related activities would be expected to be minor and short lived.

E. Aesthetics:

The new flare would be expected to be approximately 199 feet in height, and would be a source of noise. Because the project includes a flare gas recovery system, flaring as a part of normal operations would be expected to decrease. The new flare will be located within the CHS footprint, which includes the current flare, along with many other tall structures. The addition of the new flare to the existing facility is consistent with the current use of the site. However, the new flare will be located closer to the residences located just west of the refinery. Noise levels at those residences may be louder during time periods when flaring does occur.

The new flare would be subject to emissions and design standards, including the requirements of 40 Code of Federal Regulations (CFR) 60.18, which requires that flares be designed for and operated with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

Construction activity would be associated with this project. This activity would be temporary.

Overall, the impacts to aesthetics, given the project is to occur at an existing refinery operation, would be expected to be minor.

F. Air Quality:

This permit action would allow for minor changes in emissions of all pollutants from an existing source of these emissions. The changes would not be expected to result in any more than minor impacts to current air quality. Installation and utilization of flare gas treatment and recovery provides for a reduction in emissions compared to pre-project emissions, by reducing the reduced sulfur content of the captured and treated gases, and by offsetting natural gas burning by burning the gasses in refinery processes instead of in the flare.

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

No discernible change in impacts to any unique endangered, fragile, or limited environmental resources would be expected as a result of this project. Any impacts to unique endangered, fragile, or limited environmental resources as a result of this project would be expected to be minor.

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

Steam injection would be an expected part of the new flare design. However, because the existing flare will be removed from service, and because the design will include flare gas recovery, no significant change to demands on water would be expected. CHS intends to recover waste heat from the new ammonia combustor to be installed as part of the new sour water stripping process by creating steam. Although natural gas usage will be required to ensure proper destruction efficiency of the ammonia stream, heat recovery as part of this process ensures maximum use of that heat content.

As discussed in Section F. above, no more than minor impacts to current air quality would be expected as a result of this project, as the flare gas treatment and recovery process would be expected to reduce emissions from the flare, compared to if the project was not completed. Demands on water, air, and energy would be expected to be minor.

I. Historical and Archaeological Sites:

The permitting action would result in ground disturbance located within the boundaries of the existing refinery. Any impacts to any historical and archaeological sites would be expected to be minor, with no impacts at all expected.

J. Cumulative and Secondary Impacts:

Impacts to the individual physical and biological considerations above would be expected to be minor. Cumulatively, these impacts are expected to be minor. Further, secondary impacts would be expected to be minor.

8. *The following 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 Production			X			Yes
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 permitting action would not be expected to cause a disruption to any native or traditional lifestyles or communities (social structures or mores) in the area. The nature of the site will not be changed, and additional employment is not expected. Any impacts to social structures and mores would be expected to be minor.

B. Cultural Uniqueness and Diversity:

The permitting action would not be expected to cause a change in the cultural uniqueness and diversity of the area because the land is currently used as a petroleum refinery and land use would not be changing. The nature of the site will not be changed, and additional employment is not expected. Any impacts to cultural uniqueness and diversity would be expected to be minor.

C. Local and State Tax Base and Tax Revenue:

No permanent new employees would be expected for this project but contractors would likely be on-site for construction and installation. Overall crude refining capacity is not expected to change. Therefore, any impacts to the local and state tax base and tax revenue would be expected to be minor.

D. Agricultural or Industrial Production:

The permitting action would not result in a reduction of available acreage of any agricultural land as the land disturbed is at the refinery site. Changes in emissions of air pollutants would not be expected to impact agricultural productivity. Any impacts to industrial production would be expected to be minor, as no increase in refinery capacity of process units is proposed.

E. Human Health:

As described in Section 7.F and 7.H of this environmental assessment, impacts on air quality, water quality, and energy demands are expected to be minor. No more than minor impacts to human health would be expected as a result of this permitting action.

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

This permitting action would not be expected to have an impact on recreational or wilderness activities because the site is removed from recreational and wilderness areas or access routes. The action would not result in any changes in access to and quality of recreational and wilderness activities. Any impacts to recreational and wilderness activities would be expected to be minor.

G. Quantity and Distribution of Employment:

No change in the number of permanent employees currently onsite would be anticipated as a result of this permitting action. The construction process would require additional construction related work. Any impacts to the quantity and distribution of employment would be expected to be minor.

H. Distribution of Population:

This permitting action does not involve any physical change that would be expected to affect the location, distribution, density, or growth rate of the human population. The distribution of population would not be expected to change as a result of this action. Any impacts would be expected to be minor.

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:

An increase in the refinery's overall capacity is not expected. Construction activity would be required. Impacts to industrial and commercial activity would be expected on a temporary basis.

K. Locally Adopted Environmental Plans and Goals:

CHS would be required to continue to comply with the State Implementation Plan and Federal Implementation Plan and associated stipulations for the Billings/Laurel area. The Department is not aware of any locally adopted environmental plans and goals which this project would interfere with.

L. Cumulative and Secondary Impacts:

The impacts to the individual social and economic considerations above would be expected to be minor. From a cumulative viewpoint, and in consideration of secondary impacts, impacts would be expected to be minor.

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

If an EIS is not required, explain why the EA is an appropriate level of analysis: All potential effects resulting from this permitting action would be minor; therefore, an EIS is not required. In addition, the source would be applying BACT and the analysis indicates compliance with all applicable air quality rules and regulations.

Other groups or agencies contacted or which may have overlapping jurisdiction: None.

Individuals or groups contributing to this EA: Department of Environmental Quality, Permitting and Compliance Division - Air Resources Management Bureau.

EA Prepared By: Shawn Juers
Date: 8/29/2014