Montana Department of
ENVIRONMENTAL QUALITY

Brian Schweitzer, Governor

P. O. Box 200901 Helena, MT 59620-0901 (406) 444-2544 Website: www.deq.mt.gov

October 27, 2009

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

Dear Mr. Kimmet:

Montana Air Quality Permit #1821-20 is deemed final as of October 27, 2009, by the Department of Environmental Quality (Department). This permit is for the retrofit of Boiler #10 at the Laurel 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,

Vickie Walsh

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

Debbie Skibicki
Lead Environmental Engineer
Air Resources Management Bureau
(406) 444-1472

VW:DS
Enclosure

Montana Department of Environmental Quality
Permitting and Compliance Division

Montana Air Quality Permit #1821-20

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

October 27, 2009

Montana Air Quality Permit

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

MAQP #1821-20
Application Complete: 8/13/09
Preliminary Determination Issued: 9/22/09
Department Decision Issued: 10/09/09
Permit Final: 10/27/09
AFS #: 111-0012

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

Section I: Permitted Facilities

A. Plant Location/Description

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

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

B. Current Permit Action

On August 13, 2009, the Department of Environmental Quality (Department) received a complete application from CHS requesting a modification to MAQP #1821-19. CHS is proposing to retrofit the existing Boiler #10 with a lower oxides of nitrogen (NO_x) control technology burner and to update the permit limits for this unit accordingly. This project is being completed on a voluntary basis by CHS in order to improve environmental performance and boiler reliability. On September 17, 2009, the Department received a revision to this application addressing the SO_2 Best Available Control Technology (BACT) analysis for both Boiler #10 and the recently permitted Platformer Splitter Reboiler. This application revision was submitted in consultation with the Department and revises the SO_2 BACT analysis to reflect the recently finalized New Source Performance Standards Subpart Ja requirements.

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

A. National Emission Standards for Hazardous Air Pollutants

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

B. Annual Plant-wide Emission Limitations (ARM 17.8.749):

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

2. NO_x emissions shall not exceed 999.4 TPY

3. Carbon monoxide (CO) emissions shall not exceed 678.2 TPY

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

5. Particulate matter with an aerodynamic diameter of 10 microns or less (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 Continuous Emission Monitoring System (CEMS) data). The units included in each source type are listed in Section I.A of the permit analysis. The calculation basis for each unit is listed in Attachment A (Plant-Wide Refinery Limitations and Conditions Compliance Determination).

D. Reporting and Recordkeeping Requirements (ARM 17.8.749):

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

E. Testing Requirements

1. Fuel flow rates, fuel heating value, production information and other data, as needed, shall be recorded during the performance of source tests in order to develop emission factors for use in the compliance determinations (ARM 17.8.749).

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

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

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

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

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

2. All records compiled in accordance with this permit must be maintained by CHS as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department,-EPA, and the Yellowstone County Air Pollution Control Agency, and must be submitted to the Department upon request (ARM 17.8.749).

3. CHS shall notify the Department of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include a change of control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

G. Notification Requirements

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

1. All compliance source tests as required by the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

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

Section III: Limitations and Conditions for Fuel Gas and Fuel Oil Combustion Devices

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

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

2. Subpart J - Standards of Performance for Petroleum Refineries applies to all fuel gas combustion devices as applicable, with the exception of the existing refinery flare. The flare will be subject to Subpart J once EPA has approved all proposed Alternative Monitoring Plans (CHS Consent Decree Paragraphs 55 and 57).

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. Prior to the startup of Boiler #12, SO_2 emissions from the combustion of alkylation unit polymer and fuel oil in all combustion devices is limited to 127.6 tons per rolling 365-day time period (ARM 17.8.749). Periods of natural gas curtailment are not exempt from this limit.

   Following the startup of Boiler #12, 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. Following initial startup of Boiler #12, fuel oil combustion in refinery boilers is prohibited (ARM 17.8.749).

3. Refinery fuel gas burned in fuel combustion devices shall not exceed 0.10 grains of H_2S per dry standard cubic foot per rolling 3-hour average. Refinery fuel gas burned in fuel combustion devices shall not exceed 0.05 grains of H_2S per dry standard cubic foot per 12-month average (ARM 17.8.749).

4. The burning of old sour water stripper overhead (SWSOH) in any fuel gas combustion device is prohibited (CHS Consent Decree Paragraphs 43 and 50 and Appendix A).

D. Monitoring Requirements

1. CHS shall install and operate the following CEMS/Continuous emission rate monitors (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, Subparts J, 60.100-108 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 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 (tons/year) for each calendar day. CHS shall submit the quarterly emission reports within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department.

The quarterly report shall also include the following:

1. Source or unit operating time during the reporting period (Alkylation Unit and boilers burning fuel oil) and 24-hour (daily) average concentration of 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 HDS Complex

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 GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries applies to the HDS unit.

   4. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the HDS unit.

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

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

2. Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. This applies to the replacement C-201B Compressor installed in 2006.

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

D. Limitations on Individual Sources

The HDS complex desulfurizes fluidized catalytic cracking unit feedstocks. The SRU and TGTU shall together utilize up to 70.7 long tons per day (LTD) of equivalent sulfur obtained from the equipment, to manufacture elemental sulfur.

1. <u>Zone D SRU Incinerator Stack (E-407 & INC-401)</u>

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. 125 ppm_{vd}, rolling 12-month average corrected to 0% oxygen, on a dry basis,

iii. 341.04 lb/day,

iv. 14.21 lb/hr, and

v. 250 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 (E-407 & INC-401) to no more than 125 ppm_{vd} on a rolling 12-month average corrected to 0% oxygen on a dry basis (ARM 17.8.752).

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

i. 3.5 tons/rolling 12-calendar month total,
ii. 19.2 lb/day, and
iii. 0.8 lb/hr.

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

2. <u>Compressor Gas Engine Stack (C-201B)</u>

a. NO_x emissions from C-201B shall not exceed (ARM 17.8.749):

i. 30.43 tons/rolling 12-calendar month total
ii. 7.14 lb/hr

b. CO emissions from C-201B shall not exceed (ARM 17.8.749):

i. 68.59 tons/rolling 12-calendar month total

ii. 6.40 lb/hr when firing natural gas
iii. 16.10 lb/hr when firing propane

c. VOC emissions from C-201B shall not exceed 10.1 tons/rolling 12-calendar month total (ARM 17.8.749).

d. CHS shall only combust natural gas or propane in C-201B (ARM 17.8.749).

e. CHS will maintain and operate a CO catalyst on the C-201B compressor exhaust (ARM 17.8.749).

3. <u>Reformer Heater Stack (H-101)</u>

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).

4. <u>Reactor Charge Heater Stack (H-201)</u>

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. Fractionator Feed Heater Stack (H-202)

   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 Subpart J)
   b. O_2 (40 CFR 60 Subpart J)
   c. Volumetric Flow Rate (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; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors (ARM 17.8.749).

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. Startup shall be considered to be when acid gas and SWS streams are first introduced into the sulfur recovery facility. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated (ARM 17.8.749).

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 Reactor Charge Heater Stack (H-201) 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.4.b and c (ARM 17.8.105 and ARM 17.8.749).

5. The Fractionator Feed Heater Stack (H-202) 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.5.b and c (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations

1. In addition to the testing required in Section IV.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 5.

4. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Sections IV.D.1 through 5 (ARM 17.8.749).

5. Reasons for any emissions in excess of those specifically allowed in Sections IV.D.1 through 5 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

Section V: Limitations and Conditions for Boiler #10

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

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

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

3. Subpart J - Standards of Performance for Petroleum Refineries. The requirements of this Subpart apply to Boiler #10.

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

B. Emission Limitations for Boiler #10 (limitations in Section V.B are applicable prior to startup of Boiler #10 following installation of ultra-low NOx Burners (ULNBs)

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 3.83 lb/hr (ARM 17.8.752).

3. NO_x emissions shall not exceed 0.058 pounds per million British thermal units (lb/MMBtu) fired and 5.79 lb/hr (ARM 17.8.752).

4. CO emissions shall not exceed 0.10 lb/MMBtu fired and 9.99 lb/hr (ARM 17.8.752).

5. VOC emissions shall not exceed 0.015 lb/MMBtu fired and 1.50 lb/hr (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 low NO_x burners with flue gas recirculation (FGR) and have a minimum stack height of 75 feet above ground level (ARM 17.8.340 and ARM 17.8.749).

Ba. Emission Limitations for Boiler #10 (limitations in Section V.Ba are applicable upon startup of Boiler #10 following installation of the ULNBs)

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. 3.0 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 and V.Ba, 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. Prior to the startup of Boiler #10 following the installation of the ULNBs, 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.Ba, 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. Prior to the startup of Boiler #10 following the installation of the ULNBs, 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.Ba 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 (this requirement applicable upon startup of Boiler #10 following installation of the ULNBs)
v. Daily average and maximum lb/hr (this requirement applicable upon startup of Boiler #10 following installation of the ULNBs)

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

d. Monitoring downtime that occurred during the reporting period.

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

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

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

G. Notification

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

Section VI: Limitations and Conditions for the Truck Loading Rack Vapor Combustion Unit (VCU)

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

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

2. Subpart CC - NESHAP from Petroleum Refineries shall apply to, but not be limited to, the truck ("product") loading rack and VCU.
3. The product loading rack and vapor combustion unit shall be operated and maintained as follows:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

i. The VCU stack shall be 35 feet above grade (ARM 17.8.749).

B. Emission Limitations for the Truck Loading Rack VCU

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

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

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

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

C. Monitoring Requirements

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

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

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

D. Testing Requirements

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

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

3. The product loading rack VCU shall be tested for CO and NO_x, concurrently, and compliance demonstrated with the CO and NO_X emission limitations contained in Section VI.B.2 and 3, as required by the Department (ARM 17.8.105).

E. Operational and Emission Inventory Reporting Requirements

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

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

2. Subpart CC - CHS shall keep all records and furnish all reports to the Department as required by 40 CFR Part 63.654.

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

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

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

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

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

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

undergoing retrofit measures.

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

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

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

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

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

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

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

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

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

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

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

D. Limitations on Individual Sources (ARM 17.8.752)

1. Reactor Charge Heater H-901

a. 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. 2.19 tons/rolling 12-calendar month total
ii. 0.50 lb/hr

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

i. 9.00 tons/rolling 12-calendar month total
ii. 2.05 lb/hr

d. VOC Emissions from H-901 shall not exceed 0.59 tons/rolling 12-calendar month total (ARM 17.8.752).

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

2. Fractionator Reboiler H-902

a. 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. 4.40 tons/rolling 12-calendar month total
ii. 1.00 lb/hr

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

i. 8.50 tons/rolling 12-calendar month total
ii. 1.94 lb/hr

d. VOC Emissions from H-902 shall not exceed 1.19 tons/rolling 12-calendar month total (ARM 17.8.752).

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

3. Reformer Heater H-1001

a. SO_2 emissions from H-1001 shall not exceed (ARM 17.8.752):

i. 12.69 tons/rolling 12-calendar month total
ii. 5.80 lb/hr

b. NO_x emissions from H-1001 shall not exceed (ARM 17.8.752):

i. 28.31 tons/rolling 12-calendar month total
ii. 6.46 lb/hr

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

i. 400 ppmvd at 3% oxygen on a 30-day rolling average

ii. 14.15 tons/rolling 12-calendar month total
iii. 3.23 lb/hr

d. VOC Emissions from H-1001 shall not exceed 3.82 tons/rolling 12-calendar month total (ARM 17.8.752).

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

E. Monitoring Requirements (ARM 17.8.340).

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

a. O_2 (40 CFR 60, Subpart J)
b. SO_2 (40 CFR 60, Subpart J)

2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subpart Db 60.40b through 60.49b, Subparts J, 60.100-108, and Appendix B, Performance Specifications 2, 3, 4 or 4A, and Appendix F. The volumetric flow rate monitor shall, if required, comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1.

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

F. Testing Requirements

1. The Reactor Charge Heater (H-901) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section VIII.D.1.b and c (ARM 17.8.105 and ARM 17.8.749).

2. 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 contained in Section VIII. D.2.b and c (ARM 17.8.105 and ARM 17.8.749).

3. The Reformer Heater (H-1001) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section VIII.D.3.b and c (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations (ARM 17.8.749).

1. In addition to stack testing required in Section VIII.F, compliance determinations for the SO_2 limit in Section VIII.D.3 for H-1001 shall also be based upon monitoring data as required in Section VIII.E.

2. Compliance with the opacity limitation listed in Section VIII.C shall be

determined using EPA Reference Method 9 testing by a qualified observer.

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

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

1. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates and SO_2 in the H-1001 stack.

2. Monitoring downtime that occurred during the reporting period.

3. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in VIII.D.1 through 3.

4. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in VIII.D.1 through 3.

5. Reasons for any emissions in excess of those specifically allowed in VIII. D.1 through 3 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

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

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

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

2. Subpart J - Standards of Performance for Petroleum Refineries applies to Zone A's SRU #1 and #2 tail gas incinerator (SRU-AUX-4) stack.

3. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the TGTU process drains as applicable.

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

1. Subpart A – General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
2. Subpart UUU – MACT Standard for Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. CHS shall comply with Subpart UUU by complying with 40 CFR Part 60, NSPS Subpart J.

C. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in the TGTU

(ARM 17.8.304 (2)).

D. The Department determined, based on modeling provided by CHS, that the SRU-AUX-4 stack shall be maintained at a height no less than 132 feet.

E. Limitations on Individual Sources

1. 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 (Consent Decree paragraph 63 and ARM 17.8.749)

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

   c. 40.66 tons/rolling 12-month total

   d. 11.60 lb/hr

   e. 278.40 lb/day

2. CHS shall operate and maintain the TGTU on the Zone A SRU to limit 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 (CHS Inc, Consent Decree):

   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 and CO. Subpart J requirements for PM and opacity will become applicable when the third air-blower in the FCCU starts up, or as required under the CHS Consent Decree (CHS Consent Decree Paragraphs 55).

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

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

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

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

C. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed on or before November 23, 1968, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

D. Limitations on Individual Emitting Units

1. FCCU Regenerator Stack

a. CO emissions from the FCCU Regenerator Stack shall not exceed 500 ppm at 0% O_2 per 1-hour time period (CHS Consent Decree Paragraph 41, ARM 17.8.340, 40 CFR Part 60, Subpart J; and ARM 17.8.752).

b. CO emissions from the FCCU Regenerator Stack shall not exceed 100 ppm_{vd} at 0% O_2, on a 365-day rolling average basis (CHS Consent Decree Paragraph 41).

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 (CHS Consent Decree Paragraphs 32-33).

d. PM emissions from the FCCU shall be controlled with an ESP. Following the startup of the third air blower in the FCCU, PM emissions from the FCCU shall not exceed 1.0 lb PM/1,000 lb of coke burned (ARM 17.8.752).

e. NO_x emissions from the FCCU shall not exceed 161.1 tons per 12-month rolling average (limit is based on 90 ppm_{vd} at 0% oxygen on a 12-month rolling average) (ARM 17.8.752).

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

a. The FCC Charge Heater (FCC-Heater-1) shall not exceed 49.7 MMBtu/hr on a rolling 12-calendar month basis (ARM 17.8.749).

b. NO_x emissions from the FCC Charge Heater (FCC-Heater-1) shall not exceed (ARM 17.8.749):

i. 22.87 tons/rolling 12-calendar month total
ii. 6.27 lb/hr

c. CO emissions from the FCC Charge Heater (FCC-Heater-1) shall not exceed (ARM 17.8.749):

i. 19.21tons/rolling 12-calendar month total
ii. 5.26 lb/hr

E. Monitoring Requirements

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

a. CO
b. NO_x
c. SO_2
d. O_2
e. Opacity (40 CFR 63, Subpart UUU)

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 1, 2, 3, 6, and Appendix F. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1.

3. The FCCU CEMS, stack gas volumetric flow rate CEMS, and the fuel gas flow meters shall comply with all applicable requirements of the Billings/Laurel 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.

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.

F. Testing Requirements

1. CHS shall follow the stack protocol specified in 40 CFR 60.106(b)(2) to measure PM emissions from the FCCU Regenerator stack. CHS shall conduct the PM tests on an annual basis or on another testing schedule as may be approved by the Department (CHS Consent Decree Paragraph 38 and ARM 17.8.105).

2. Following the startup of the third blower in the FCCU, the FCC Charge Heater (FCC-Heater-1) shall be tested annually, or according to another testing/ monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section X.D.2.b and c (ARM 17.8.105 and ARM 17.8.749).

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 with the opacity limitation listed in Section X.C shall be determined using EPA reference method 9 observations by a qualified observer or a certified

continuous opacity monitor system (COMS).

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

CHS shall submit quarterly emission reports to the Department based on data from the installed CEMS/CERMS. Emission reporting for CO from the emission monitor shall consist of a daily maximum 1-hour average (ppm) for each calendar day. CHS shall submit the quarterly emission reports within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The quarterly report shall also include the following:

1. Source or unit operating time during the reporting period and the 7-day and 365-day rolling average 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.

5. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section X.D (ARM 17.8.749).

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

Section XI: Limitations and Conditions for the Naptha Hydrotreating Unit, Delayed Coker Unit and Zone E SRU/TGTU/TGI

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

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

2. Subpart J - Standards of Performance for Petroleum Refineries applies to the NHT Charge Heater (H-8301), the Coker Charge Heater (H-7501), and the Zone E SRU/TGTU/TGI.

3. Subpart GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the Naptha Hydrotreating Unit and the Delayed Coker Unit fugitive piping equipment in VOC service.
4. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the Delayed Coker Unit process drains.

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

1. Subpart A – General Provisions applies to all equipment or facilities subject to a

NESHAP for source categories subpart as listed below.

2. Subpart CC – Refinery MACT I shall apply to, but not be limited to, affected sources or the collection of emission points as defined in this subpart.

3. Subpart UUU – Refinery MACT II shall apply to, but not be limited to, the Zone E SRU/TGTU/TGI.

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

D. Limitations on Individual Sources

1. NHT Charge Heater (H-8301)

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

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

3. The Coker unit flare shall operate with a continuous pilot flame and a continuous pilot flame-operating device and meet applicable control device requirements of 40 CFR Part 63.11 (40 CFR 63.11, ARM 17.8.752).

4. VOC emissions from the Sour Water Storage Tank (TK-129) shall be controlled by the installation and use of an internal floating roof and a submerged fill pipe (ARM 17.8.752).

5. VOC emissions from the Coker Sludge Storage Tank (TK-7504) shall be controlled by the installation and use of a fixed roof, a submerged fill pipe, and a conservation vent (ARM 17.8.752).

6. Coke processing operations

a. CHS shall store onsite coke in the walled enclosure for coke storage only. Onsite coke storage shall be limited to a volume that is contained within the walled enclosure. Storage of coke outside of the walled enclosure is prohibited (ARM 17.8.752).

b. The coke pile shall not exceed the height of the enclosure walls adjacent to the pile at any time (ARM 17.8.752).

c. CHS shall not cause or authorize emissions to be discharged into the atmosphere from coke handling without taking reasonable precautions to control emissions of airborne particulate matter. CHS shall wet the coke as needed to comply with the reasonable precautions standard (ARM 17.8.308 and ARM 17.8.752).

d. CHS shall install and maintain enclosures surrounding the coke conveyors, coke transfer drop points (not including the location at which coke is transferred from the front-end loader to the initial coke sizing screen), and crusher (ARM 17.8.752).

e. CHS shall install and maintain a telescoping loading spout for loading coke into railcars (ARM 17.8.752).

f. Alternate Coke Handling Method: In the event the conveyors are inoperable (as described in Section XI.D.6.d and e) due to either planned or unplanned maintenance activities, CHS may transport uncrushed coke only from the coke storage area to the railcar using a front-end loader. The requirements specified in Section XI.D.6.a – c still apply. The alternate coke handling method is limited to 24 batches per year (ARM 17.8.752).

7. Zone E SRU/TGTU/TGI

a. 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).

E. Monitoring requirements

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

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

i. SO_2 (40 CFR 60, Subpart J)
ii. O_2 (40 CFR 60, Subpart J)
iii. Volumetric Flow Rate (Billings/Laurel SO_2 SIP)

2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subpart Db 60.40b through 60.49b, Subparts J, 60.100-108, and Appendix B, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1

3. The Delayed Coker Unit 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.

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.

F. Testing Requirements

1. The NHT Charge Heater (H-8301) 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.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. Initial SO_2 testing shall be performed within 60 days of the date the Zone E SRU/TGTU/TGI achieves maximum production. 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.

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. For non-minor (defined in the June 12, 1998 Stipulation) flaring events, CHS shall comply with the reporting requirements identified in Section (3)(A)(5) of Exhibit A-1 of the Stipulation signed by the Board of Environmental Review on June 12, 1998 (ARM 17.8.749).

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. CO emissions from Boiler #11 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, Subparts J, 60.100-108, and Appendix A, Appendix B, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F.

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

4. With exception to the initial performance test period, compliance with the lb/MMBtu limit(s) will be demonstrated using statistically significant F-factor values. The factor will be updated on a regular basis using data from all valid fuel gas samples representative of the fuel gas burned in Boiler #11. The method of compliance demonstration involving F-factor statistical significance is subject to change upon agreement with the Department and CHS (40 CFR 60, Appendix A, Reference Method 19).

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:

   i. Average lb/hr per calendar day
   ii. Total lb per calendar day
   iii. 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:

   i. Average lb/MMBTU per calendar day
   ii. Total tons per month
   iii. 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. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section XII.F.

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

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

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

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

2. Subpart R – Gasoline Distribution MACT

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

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. 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).

D. Monitoring and Testing Requirements

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

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

3. The VCU shall be initially tested for VOCs, and compliance demonstrated with the emission limitation contained in Section XIII.C.1 within 180 days of initial startup and continue on an every 2-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).

4. The VCU shall be initially tested for CO and NO_x, concurrently, and compliance demonstrated with the CO and NO_x emission limitations contained in Section XIII.C.2 and 3 within 180 days of initial start up (ARM 17.8.105).

Section XIV: Limitations and Conditions for Boiler #12

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

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

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

3. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to Boiler #12.

4. Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries applies to the refinery fuel gas supply lines to Boiler #12.

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

C. Limitations on Boiler #12

1. SO_2 emissions from Boiler #12 shall not exceed (ARM 17.8.752):

a. 0.05 grains/dscf H_2S refinery fuel gas, rolling 12-month average

b. 7.88 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. CO emissions from Boiler #12 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).

7. Within 180 days of initial startup of Boiler #12, CHS shall no longer operate Boiler #4. One year after initial startup of Boiler #12, CHS shall no longer operate Boiler #5 (ARM 17.8.749).

D. Monitoring requirements

1. CHS shall install and operate the following (CEMS/CERMS) for Boiler #12:

a. NO_x (40 CFR 60, Subpart Db and Consent Decree Paragraph 52)
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 J, 60.100-108, 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:

    i. Average lb/hr per calendar day
    ii. Total lb per calendar day
    iii. 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:

    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

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 ppmv 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 initially tested for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Sections XV.D.2 and 3 (ARM 17.8.105 and ARM 17.8.749).

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

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

1. 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

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:

i. Average lb/hr per calendar day
ii. Total tons per month

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

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

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

H. Notification Requirements

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

Section XVI: Platformer Heater (P-HTR-1)

A. Emission Limitations

1. By December 31, 2011, the Platformer Heater (P-HTR-1) shall be fitted with ULNBs (ARM 17.8.749 and CHS Consent Decree Paragraph 49).

2. By December 31, 2011, the NO_x emission rate for the Platformer Heater (P-HTR-1) shall not exceed 0.04 lb/MMBtu-HHV, rolling 365 day average. EPA may approve an alternative permit limitation for periods of annual catalyst regeneration (ARM 17.8.749 and CHS Consent Decree Paragraphs 44, 49, and 173)

3. The heat input rate for the Platformer Heater (P-HTR-1) shall not exceed 131 MMBtu-HHV/hr, rolling 365-day average (ARM 17.8.749 and CHS Consent Decree Paragraphs 44 and 173).

B. Monitoring Requirements

1. CHS shall install and operate CEMS to measure NO_x, CO, and O_2 by no later than the date of the installation of the ULNBs on the Platformer Heater (P-HTR-1) (CHS Consent Decree Paragraph 52)

2. CHS shall install, certify, calibrate, maintain, and operate the CEMS in accordance with the requirements of 40 CFR 60.11, 60.13, and Part 60 Appendix A and the applicable performance specification test of 40 CFR Part 60,

Appendices B and F (CHS Consent Decree Paragraph 52).

3. CEMS are to be in operation at all times when the emission unit is 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 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 the Platformer Heater (P-HTR-1). 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).

C. 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. NO_x emission data from the CEMS and fuel gas flow rate meter. The NO_x emission rate shall be reported for the rolling 365-day averaging period.

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

3. Monitoring downtime that occurred during the reporting period.

4. A summary of excess emissions for each pollutant and averaging period identified in Section XVI.A.

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

D. Notification Requirements

CHS shall provide the Department (both the Billings regional office and the Helena office) with written notification of the actual installation of the ULNBs on the Platformer Heater (P-HTR-1) within 15 days after the actual installation date (ARM 17.8.340 and ARM 17.8.749).

Section XVII: General Conditions

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

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

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

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

E. Appeals – Any person or persons jointly or severally adversely affected by the Department’s decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department’s decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department’s decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department’s decision on the application is final 16 days after the Department’s decision is made.

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

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

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

ATTACHMENT A

Plant-Wide Refinery Limitations and Conditions
Compliance Determination

1. Gas fired external combustion

   a. 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: Monthly fuel oil use (lb) per combustion unit, test for fuel oil Sulfur content pursuant to Billings-Laurel SO_2 SIP, and sulfur content and specific gravity of alkylation unit polymer pursuant to Appendix G of the CHS Consent Decree.

   b. NO_x, CO, PM_{10}/PM, VOC

      i. Calculation Basis: AP-42 Section 1-3 (9/98 revision including the 4/28/00 Errata)
      ii. Key Parameters: Monthly fuel oil use (lb) per combustion unit

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 J, and FCCU Regenerator flue gas flow rate.

d. PM_{10}/PM

i. Calculation Basis: Site-specific emission factor from catalyst mass balance studies, stack test results and particle size distribution data
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: EPA TANKS4.0
ii. Key Parameters: Monthly volume of material throughput from yield accounting, material property data (VP, MW, etc.)

Permit Analysis
CHS Inc. – Laurel Refinery
Montana Air Quality Permit #1821-20

I. Introduction/Process Description

A. Site Location/Description

The CHS Inc. (CHS) Laurel Refinery is a petroleum refinery located in the South ½ of Section 16, Range 24 East, Township 2 South, in Yellowstone County. A complete list of permitted equipment is available in the permit, with the exception of the source categories for the Plant-wide Applicability Limit (PAL), which are listed below.

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

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

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

3. Gas-fired internal combustion source, includes: Platformer recycle turbine, Zone D compressor gas engine (C-201B);

4. FCC unit (FCCU) Regenerator;

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

6. Zone D SRU Incinerator;

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

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

9. Wastewater source type includes: old American Petroleum Institute (API) separator, Zone D API separator, ULSD Unit Wastewater, TGTU Wastewater; Benzene Reduction Unit Oily Water Sewer

10. Cooling tower sources: #1 cooling tower (CT), #2 CT, #3 CT, #5 CT, and #6 CT;

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

12. Storage tanks: tank numbers 2, 7, 12, 41, 47, 56, 60, 61, 62, 63, 65, 66, 67, 68, 70, 71, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 85, 86, 87, 88, 91, 92, 93, 94, 95, 96, 97, 98, 99, 100, 101, 102, 103, 104, 105, 106, 107, 108, 109, 110, 111, 112, 113, 114, 115, 116, 117, 118, 119, 120, 121, 122, 123, 126, 127, 128, 129, B-1, B-2, B-7, firetk 2, firetk 3, firetk 4, TGTU-VSSL-6, and coker sludge storage tank (TK-7504).

B. Permit History

On May 11, 1992, Cenex Harvest States Cooperatives (Cenex) was issued **Permit #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.

Permit #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 Permit #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. Permit #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 **Permit #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
		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.

Permit #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.

Permit #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.

Permit#1821-05 replaced Permit #1821-04.

Permit #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. Permit #1821-06 replaced Permit #1821-05.

Permit #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. Permit #1821-07 replaced Permit #1821-06.

On June 3, 2002, the Department received a request from Cenex to modify Montana Air Quality Permit (MAQP) #1821-07 to remove all references to 8 temporary, portable electricity generators. The generators were permitted under Permit #1821-06, with further clarification added in Permit #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:

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

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

On May 4, 2006, the Department received a complete application from CHS to incorporate the final design of three emission sources associated with the new 15,000 BPD delayed coker unit project permitted under MAQP #1821-13. The final design capacities have increased for the new NHT Charge Heater, the new Coker Charge Heater and the new Boiler No. 11. The application also includes a request to reduce the refinery-wide fuel oil burning 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 permited 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. 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 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 Benzne Reduction project.

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.

C. Current Permit Action

On August 13, 2009, the Department received a complete application from CHS requesting a modification to MAQP #1821-19. CHS is proposing 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 is being completed on a voluntary basis by CHS in order to improve environmental performance and boiler reliability. On September 17, 2009, the Department received a revision to this application addressing the 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 revises the SO_2 BACT analysis to reflect the recently finalized NSPS Subpart Ja requirements. **MAQP #1821-20** replaces MAQP #1821-19.

D. Response to Public Comments

Person/Group Commenting	Permit Reference	Comment	Department Response
CHS	Section V.B. of the MAQP	As a result of the project, emission limitations for SO2, NOx, CO and VOC are being modified. CHS requests that the permit continue to list the current limits and identify the time at which the new limits become effective. The new limits become effective 180 days after initial startup or 60 days after reaching the full operating rate after the Boiler 10 retrofit is complete.	The Department agrees that the existing Boiler 10 emission limits remain applicable until installation is complete for the ULNBs in that unit. Therefore, there are now two sections for emission limitations, Sections V.B and V.Ba. The Department will delete the pre-retrofit emission limitations in the permit action that follows the completion of Boiler 10 retrofit (indicated by the notification by CHS of the installation of the ULNBs).

			With respect to the time at which the new limits apply, the Department disagrees that they are not applicable until 180 days after initial startup. The Department acknowledges that CHS would be allowed 180 days to demonstrate compliance with the limits, however, it is the Department's position that the limits are applicable once the unit has started up.
CHS	Section V.C.3 of the MAQP	There is no regulation that requires installation and operation of a CO CEMS/CERMS on Boiler #10. CHS requests that this requirement be removed from the permit.	Pursuant to ARM 17.8.749, the Department has authority to condition permits "to assure compliance with the Federal Clean Air Act, with the Clean Air Act of Montana, and rules adopted under those acts." The Department has required a CO CEMS to ensure practical enforceability of the CO BACT limit on this unit.
CHS	Section V.E.2 of the MAQP	CHS requests that the first sentence of this requirement be clarified, as follows: "With exception of the initial oerformance test period, compliance with the lb/MMBtu limit(s) will be demonstrated using statistically significant F-factor values." Additionally CHS requests that this requirement be clarified in Section XII.D.4 (Boiler 11) and Section XIV.D.4 (Boiler 12).	The clarification has been made.
CHS	Section V.E.4 of the MAQP	CHS requests that this permit condition be removed. There is no regulation that requires installation and operation of a CO CEM on Boiler #10.	See response for Section V.C.3 above.

E. 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).

The natural gas-fired compressor engine (C-201B) is utilized by the make-up/recycle gas section of the HDS unit. Two combined compressors operate in parallel at 50% of design duty or at 2/3 of machine design capacity. Each compressor is designed for 75% of the design process duty. The gas-fired engine is a 2000-HP (horsepower) rated unit. For purposes of the application, pollutant emission rates are based on normal operating load of 1060 HP (7918 scf/hr). The compressor engine will not fire refinery fuel gas; instead, natural gas will be burned with propane as a contingency fuel. Due to piston failure of C-201B in 2006, an identical replacement engine was installed, which will be subject to NSPS and MACT standards.

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 - A new SWS was constructed, which replaced the operation of the older existing SWS. The new SWS unit serves the existing and proposed facilities of this HDS project. The old SWS cannot be removed, however, and functions only as the back-up unit. Sour water from a variety of sources in the refinery is accumulated in the sour water storage tank where hydrocarbons are separated. The hydrocarbon is sent to the existing slop oil system for recovery. The gas vapors from the sour water tank are compressed and sent to the tail gas unit for sulfur recovery. Sour water from the storage tank is pumped into the SWS tower. Steam heat is applied to the stripper to remove H_2S and NH_3 from the water. The stripper overhead gas containing H_2S and NH_3 is sent to the new SRU for sulfur recovery and incineration of NH_3.

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.

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 applies to Boilers #10, #11, and #12.

   c. Subpart J - Standards of Performance for Petroleum Refineries shall apply to the SRU Incinerator Stack (E-407 & INC-401), Fractionator Feed Heater Stack (H-202), Reactor Charge Heater Stack (H-201), the FCCU Regenerator, and all fuel gas combustion devices, as applicable, with the exception of the Naphtha Unifier Splitter Heater, the Hydrogen Reformer Heater (H-101), the

Alkylation Hot Oil Belt Heater, the Loading Rack Vapor Combustion Unit, and the Refinery Flare (CHS Consent Decree paragraphs 55, 57, and Appendix F).

d. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 shall apply to Boiler #12, the Platformer Splitter Reboiler (P-HTR-30, and the Refinery Flare (once new connections are made). Note: Portions of Subpart Ja are currently stayed until February 24, 2009. EPA has proposed revisions to Subpart Ja with respect to certain provisions for flares. Once the stay is lifted or final revised Subpart Ja provisions are promulgated, those final provisions affecting flares will apply to the Refinery Flare.

e. Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries shall apply to the HDS Complex, including, but not be limited to, the SRU Incinerator Stack (E-407 & INC-401), Superior Clean Burn II 12 SGIB (C201-B), Fractionator Feed Heater Stack (H-202), Reactor Charge Heater Stack (H-201), the Reformer Heater Stack (H-101), refinery fuel gas supply lines to the Boilers #10, and #12, the fugitive ULSD Unit and Hydrogen Plant fugitive piping equipment, the Zone A TGTU fugitive piping equipment in VOC service, the Delayed Coker Unit fugitive piping equipment in VOC service and the Naptha Hydrotreating Unit and any other applicable equipment constructed or modified after January 4, 1983.

f. Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, shall apply to all of the fugitive VOC emitting components added in the Benzene Reduction Unit project and any other applicable equipment constructed, reconstructed, or modified after November 7, 2006.

g. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply, but not be limited to, the HDS Complex, SRU Incinerator Stack (E-407 & INC-401), Superior Clean Burn II 12 SGIB (C201-B), Fractionator Feed Heater Stack (H-202), Reactor Charge Heater Stack (H-201), the Reformer Heater Stack (H-101), the ULSD Unit and Hydrogen Plant wastewater streams, the Zone A TGTU process drains, the Delayed Coker, the Zone E SRU/TGTU/TGI, the Benzene Reduction Unit, and any other applicable equipment. NSPS Subpart QQQ does not apply to boiler #10, since the boiler drains will not contain any oily wastewater.

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

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

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

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

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

b. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries shall apply to, but not be limited to, the Product Loading Rack, tank 96 when it is utilized for gasoline service, and certain parts of the Benzene Reduction Unit.

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

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

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

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

2. <u>ARM 17.8.402 Requirements</u>. 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. <u>ARM 17.8.504 Air Quality Permit Application Fees</u>. 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. <u>ARM 17.8.505 Air Quality Operation Fees</u>. 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. <u>ARM 17.8.740 Definitions</u>. This rule is a list of applicable definitions used in

this chapter, unless indicated otherwise in a specific subchapter.

2. 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 August 5, 2009, 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). This modification will not cause a project-related emissions increase greater than significant levels and, therefore, does not require a New Source Review (NSR) analysis. The emissions changes are as follows:

Pollutant	Actual Emissions (TPY)	Boiler #10 Retrofit PTE (TPY)	Project- Related Emissions Increases (TPY)	PSD Significance Level (TPY)	Significant?
NO_x	12.06	13.14	1.08	40	No
SO_2	0.29	4.14	3.85	40	No
TSP	1.69	3.50	1.81	25	No
PM_{10}	1.69	3.50	1.81	15	No
CO	23.45	21.90	-1.55	100	No
VOC	0.05	2.23	2.18	40 (for ozone)	No

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 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 #1821-20 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, GGG, GGGa, and QQQ).

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

f. This source is not a Title IV affected source, nor a solid waste combustion unit.

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

Based on these facts, the Department determined that CHS is a major source of emissions as defined under Title V. CHS' Title V Operating Permit, containing revisions agreed to by CHS and the Department to resolve contested case # BER 2007-23-AQ, was issued final and effective on October 31, 2008. Further, the current permit action constitutes a significant modification to the existing Title V Operating Permit; therefore, in accordance with ARM 17.8.1227, CHS submitted a Title V permit application for this project concurrent with the Montana Air Quality permit application.

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

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

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

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

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

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

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

Chemical Compound	Hourly Conc µg/m3	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 µg/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.

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

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

Chemical Compound	Modeled Conc. µg/m^3	Table 1* Conc.1 µg/m^3	Table 2* Conc. µg/m^3
Benzene	1.81E-02	1.20E-02	7.10E-01
Ethyl Benzene	8.29E-04	--	1.00E+01
Napthalene	4.08E-05	--	1.40E-01
Toluene	1.22E-02	--	4.00E+00
Xylenes	4.35E-03	--	3.00E+00
Hexane	2.68E-02	--	2.00E+00

Total concentrations = 0.0623
*Refers to ARM 17.8.770

The modeling demonstrated that the ambient concentrations of HAPs, with the exception of Benzene, are less than the concentrations contained in Table 1 and Table 2 of ARM 17.8.770; therefore, these HAPs were excluded from further review.
A risk assessment for Benzene was calculated because the predicted ambient concentration was greater than the concentration contained in Table I of ARM 17.8.770. The modeled benzene concentration was compared to EPA Region III's, "Risk-Based Concentration (RBC) Table," dated October, 2005. RBC screening levels represent concentrations which are determined to present a lifetime cancer risk of no greater than 1 x 10^{-6}. The RBC concentration for benzene is listed as 2.3 x 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.

III. BACT Determination

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

A BACT analysis was submitted by CHS in MAQP application #1821-20, addressing some available methods for controlling emissions from Boiler #10, as well as SO_2 emissions from the Platformer Splitter Reboiler (P-HTR-3), which was originally permitted under MAQP #1821-18. The Department reviewed these methods as well as previous BACT determinations. The following control options have been reviewed by the Department in order to make the following BACT determination.

A. NO_x Emissions

NO_x are formed as part of the combustion process and are generally classified as either thermal NO_x or fuel NO_x. Thermal NO_x is formed by the thermal dissociation and subsequent reaction of the nitrogen and oxygen in the combustion air at high temperature. The amount of thermal NO_x formation is a function of the burner, process heater, or boiler's fire box/combustion chamber design, flame temperature, residence time at flame temperature, combustion pressure, and fuel/air ratios in the primary combustion zone. The rate of thermal NO_x formation is an exponential function of the flame temperature.

Fuel NO_x is formed by the gas phase oxidation of the nitrogen that is chemically bound in the fuel. Fuel NO_x formation is largely independent of combustion temperature and the nature of the organic nitrogen compound. Its formation is dependent on fuel nitrogen content and the amount of excess combustion air. Refinery fuel gas contains negligible amounts of fuel bound nitrogen. As such, thermal NO_x is the predominant type of NO_x formed in Boiler #10.

The following NO_x control technologies have been identified as commercially available for boilers: low nitrogen fuels, water-injection style burners, burners with air to fuel ratio control, low NO_x burners (LNB), ultra low NO_x burners (ULNB) including burners with internal or external flue gas recirculation (FGR), Next Generation ULNB, non-selective catalytic reduction (NSCR), selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR), some of which can be used in combination with each other.

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

The use of SCR without combustion controls is not considered realistic for the retrofit of this boiler since it is already equipped with a LNB and FGR. Therefore, SCR alone will not be analyzed further. The other control options are technically feasible for Boiler #10 and are listed in the table below in order of control effectiveness.

BACT Control Hierarchy for NO_x

Control Technology	Nominal NO_x Performance (lb/MMBtu)
ULNB + SCR	0.005
ULNB + FGR	0.02
ULNB	0.04
LNB	0.08
Conventional Burner	0.20

The top control technology, ULNB + SCR, was shown to have an incremental cost-effectiveness going from ULNB + FGR to ULNB + SCR of greater than $35,000 per ton of NO_x removed (an additional 10.9 tons of NO_x removed with ULNB + SCR). This cost is economically prohibitive and, for this reason, ULNB + SCR was rejected as NO_x BACT for Boiler #10.

The next top-ranked control technology, ULNB + FGR, is proposed as NO_x BACT for the retrofit of Boiler #10. Review by burner manufacturers indicates that a NO_x performance level of 0.03 lb NO_x/MMBtu, on a 365-day rolling average is technically achievable in a retrofit of Boiler #10. This performance level is achievable on a long term basis for the following reasons:

- NO_x control performance statements from boiler and burner suppliers are based on set operating conditions. These conditions are provided to the suppliers by CHS and are based on the expected typical operating conditions of the boiler. These conditions include such things as a specified ambient temperature range. As such, any significant change to any one of the conditions poses a significant challenge to achieving the maximum NO_x control over a short-term period, such as hourly or daily.

- CHS has closely monitored the NO_x emissions on refinery boilers with NO_x CEMS. It is with this monitoring that CHS has identified several process disturbances that impact the performance of the boilers from a NO_x emissions stand-point. These include boiler load changes, boiler fuel heating value fluctuations, increased hydrogen content in the boiler fuel, and increased olefin content in the boiler fuel. All of these conditions negatively impact the boiler's NO_x control but are variables that are typical in the operating environment of a refinery.

CHS recently installed two new boilers (Boilers #11 and #12), and identified ULNB + FGR as NO_x BACT for these boilers, with a performance level of 0.02 lb NO_x/MMBtu. This level is not achievable for Boiler #10. A significant difference between the two new boilers and Boiler #10 is the capacity for FGR. The capacity to re-circulate flue gas is fixed to the original Boiler #10 design. The firebox design pressure, FGR line and blower capacity all remain unchanged in this retrofit. NO_x emissions performance for the retrofit of Boiler #10 is achieved through the use of waste steam injection and 10% FGR. Boilers #11 and #12 were designed for 24% FGR (natural gas) and 27% (refinery fuel gas). Increasing the FGR capacity of Boiler #10 to similar levels achieved in Boilers #11 and #12 would involve increasing the blower capacity and firebox design pressure. Costs associated with making these changes would be similar to a complete boiler replacement. For this reason, it is not considered feasible to increase FGR capacity on Boiler #10.

Therefore, the Department has determined that ULNB + FGR with a NO_x emissions limitation of 0.03 lb/MMBtu-HHV on a rolling 365-day average constitutes NO_x BACT for the Boiler No. 10.

B. CO Emissions

In an ideal combustion process, all of the carbon and hydrogen contained within the fuel are oxidized to carbon dioxide (CO_2) and water (H_2O). The emission of CO and VOC in a combustion process is the result of incomplete organic fuel combustion. Operating conditions such as low temperatures, insufficient residence time, low oxygen levels due to inadequate mixing, and/or a low air-to-fuel ratio in the combustion zone result in CO formation. CO emissions may also increase at reduced firing rates due to lowering of flame temperatures and less efficient combustion. VOC emissions result from incomplete combustion of heavier molecular weight components of the refinery fuel gas. In addition, VOC emissions are produced to some degree by the reforming of hydrocarbon molecules in the combustion zone.

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

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

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

ULNB technology has advanced significantly, driving down NO_x and CO emissions to lower levels. However, at some level a trade-off exists between low NO_x and low CO emissions. Attempting to tune an ULNB for both low NO_x and low CO can result in unsteady emissions or an unsteady flame, neither of which is desirable. While tuning a burner to achieve lower NO_x, the possibility exists that CO emissions will not be minimized. Conversely, an ULNB can be tuned for lower CO emissions at the cost of increased NO_x. Achieving low CO becomes especially problematic in large vertical, cylindrical furnaces where temperatures are stratified, thus allowing cool spots for CO to form.

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

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

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

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

Oxidation catalysts have traditionally been applied to the control of CO emissions from natural gas fired combustion turbines located in CO nonattainment areas. This technology uses precious metal based catalysts to promote the oxidation of CO and un-burnt hydrocarbon to CO_2. Refinery fuel gas contains sulfur as H_2S, which when burned oxidizes to SO_2. Oxidation catalyst is not applied to sources where sulfur bearing fuels are fired because any SO_2 formed by the combustion process is further oxidized to SO_3 which readily becomes sulfuric acid mist in the atmosphere. This increase in sulfuric acid mist would increase plume visibility and increase the amount of PM_{10} emitted. The sulfuric acid would also cause rapid corrosion of the control equipment and stack. Thus, oxidation catalyst is not considered feasible for this application.

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

EM_x is second generation $SCONO_x$ NO_x absorber technology. EM_x is a catalyst-based post-combustion control, which simultaneously oxidizes CO to CO_2, VOC to CO_2 and water, and NO to NO_2, subsequently adsorbing the NO_2 onto the surface of a catalyst where a chemical reaction removes it from the exhaust stream.

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

Based on this analysis, the one technically feasible control option for CO control is proper burner design and operation. Reduction of CO will be accomplished by controlling the combustion temperature, residence time, and available oxygen. Normal combustion practices at the CHS refinery will involve maximizing the heating efficiency of the fuel in an effort to minimize fuel usage. This efficiency of fuel combustion will also minimize CO formation. Consistent with all CO BACT determinations for refinery fuel gas fired sources found in the RBLC, proper design and good combustion techniques constitute CO BACT for Boiler #10. The CO emission estimates for the retrofit Boiler #10 are based on 0.05 lb/MMBtu – HHV as guaranteed by the burner manufacturer. A lower CO limit is not deemed feasible for this boiler because the proposed CO concentration is tied to the proposed NOx BACT limit of 0.03 lb NO_x/MMBtu-HHV, 365-day rolling average. Additionally, during turndown operations, this boiler may experience an increase in CO emissions. This phenomenon is a result of low NO_x burner design/low firebox temperatures that are unable to force completion of fuel oxidation, which would convert all of the carbon in the fuel being fired to CO_2. For these reasons, CHS is proposing a CO BACT limit of 0.05 lb/MMBtu-HHV on a 365-day rolling average basis.

As discussed above, during turndown operations, the boiler may experience an increase in CO emissions. During boiler shutdown operations, there is a time period at low rates to allow other boilers to ramp up and meet the refinery steam demand. During startup operations, there is a heat-up period where the boiler must remain at low rates as the boiler internals heat up. To address this issue, CHS is proposing a short term CO limit of 10.0 lb/hr (based on 0.10 lb/MMBtu-HHV), on a 24-hour average basis, during periods of boiler startup and shutdown.

C. VOC emissions

VOC emissions closely track CO emissions, since an increase in CO generally indicates incomplete combustion and an increase in VOC emissions. As is consistent with similar recently permitted sources, CHS proposed and the Department concurs that proper design and good combustion techniques constitute VOC BACT for the retrofit of Boiler #10.

D. SO_2 emissions

SO_2 emissions from combustion sources are a direct function of the sulfur content of the fuel that is burned. Reduced sulfur compounds in the fuel are readily oxidized to SO_2 and to a small extent SO_3. CHS intends to primarily fire low sulfur refinery fuel gas in Boiler #10 and the Platformer Splitter Reboiler (P-HTR-3).

Emissions of SO_2 from combustion devices can be controlled by fuel specifications or by using post-combustion controls. Fuel specifications limit SO_2 emissions by specifying a maximum allowable sulfur concentration in the gaseous fuels combusted in the combustion device. Post-combustion control for SO_2 involves treating the combustion gases with an alkaline reagent which reacts with the SO_2 to produce a sulfur salt byproduct. This type of post-combustion control process is generally termed flue gas desulfurization (FGD). FGD technology is well-established for sources with relatively high levels of sulfur emissions. It has not been used on refinery combustion devices, generally because fuel specification is a more cost-effective means of reducing SO_2 emissions.

Pipeline quality natural gas has very low sulfur content, generally in the form of mercaptans used for odorization and trace quantities of reduced sulfur compounds. SO_2 emissions from natural gas-fired equipment are generally considered the lowest practically achievable for that fuel and do not require additional control equipment.

Refinery fuel gas has a higher sulfur content than the natural gas purchased from a pipeline. The refinery gas sulfur content is dependent on the removal efficiency of the fuel gas amine scrubbing units in a refinery. CHS plans to operate the existing amine scrubbing system to produce refinery gas with less than 60 ppmv H_2S, on an annual average basis (NSPS Subpart Ja). On a short-term basis, variability in the operation of the amine scrubbing system may result in spikes in the sulfur concentration of the lean gas produced (i.e, as much as 161 ppmv sulfur on a 3-hour average basis.)

FGD is commonly used for control of SO_2 from solid fuel-combustion, such as coal.

FGD technology can be achieved through a variety of wet or dry scrubbing processes. It has demonstrated control efficiencies of up to 95% on coal-fired combustion systems. The use of FGD is not considered technically feasible for Boiler #10 or the Platformer Splitter Reboiler (P-HTR-3) heater because the design would have to be significantly altered. In addition, FGD technology is not commercially demonstrated on small refinery combustion devices because it is cost-prohibitive compared to the cost of desulfurizing the fuel gas.
The top-performing feasible SO_2 control technology is the firing of 100% purchased natural gas in the boiler and heater, because of the very low sulfur content of natural gas. The next most effective control technology is the use of refinery fuel gas treated to sulfur levels that meet the recently finalized NSPS Subpart Ja.

The calculated cost of using purchased natural gas, per ton of SO_2 reduced as a result, is greater than $1 million/ton SO_2, based on a natural gas price of approximately $5/MMBtu. As such, this option is not considered cost effective, and is rejected as BACT. An annual average refinery fuel gas H_2S content of 60 ppmv constitutes BACT for Boiler #10 and the Platformer Splitter Reboiler (P-HTR-3).

E. $PM/PM_{10}/PM_{2.5}$ Emissions

Particulate matter emissions from boilers with properly designed and tuned burners are inherently low when gaseous fuels are used. Filterable particulate matter in gas-fired sources that are properly tuned originates from the dust in the inlet air and metal erosion within the sources (e.g., tubes, combustion surfaces, etc.). Sources that are not properly tuned may also produce filterable particulate matter as a result of incomplete combustion of fuel hydrocarbons that agglomerate to form soot particles. These particles pass through the firebox and are emitted in the exhaust gas. Condensable particulate matter can result from oxidation of fuel sulfur (to sulfur trioxide) and from incomplete combustion of hydrocarbons in the fuel. For the purposes of this analysis, all of the particulate matter emitted from the retrofit boiler is assumed to be PM_{10} and $PM_{2.5}$. Control options available include:

- proper equipment design and operation
- fuel specification
- post-combustion controls, such as a baghouse or electrostatic precipitator (ESP).

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

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

Gaseous fuels have differing specifications, depending on their source. Natural gas is processed to meet certain specifications such that the key combustion parameters are relatively consistent in most parts of the country. $PM/PM_{10}/PM_{2.5}$ emissions from properly designed and controlled natural gas-fired equipment are generally considered the lowest achievable.

Refinery fuel gas is a byproduct of refining operations that is typically processed and consumed on-site without the ability of meeting pipeline natural gas specifications. With proper burner design and operation, refinery gas-fired sources can achieve $PM/PM_{10}/PM_{2.5}$ emission levels that approach those of natural gas. Combustion of refinery gas will result in slightly higher $PM/PM_{10}/PM_{2.5}$ emissions than combustion with natural gas because of the higher molecular weight hydrocarbons and the presence of sulfur compounds. The presence of higher molecular weight hydrocarbons in refinery gas makes it more difficult to properly tune the burner to minimize the formation of particulates. The higher level of sulfur compounds in refinery fuel gas results in production of more SO_3, a compound that contributes to condensable particulate matter emissions.

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

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

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

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

While these controls are theoretically feasible for application to gas-fired boilers, fabric filters and ESPs are not considered technically feasible for the control of $PM/PM_{10}/PM_{2.5}$ emissions from gas fired boilers. These controls would not be expected to provide any significant emissions reductions because of the already low particulate matter emission rate and the fine particle size of the emissions from these units. The fact that such controls have not been applied to similar sources is a clear indication of technical infeasibility. Additional technical support for this conclusion is outlined below.

Fabric filters rely on the build-up of a filter cake to act as a filtering medium for collection of particulate matter. Periodically, this filter cake is removed and filtration efficiency declines until a filtering cake can be re-established. The ultra-fine size of particulate emissions from firing of gaseous fuels is such that no cake could be established in a fabric filter. Instead, the very fine particles would be expected to either pass through the bags uncontrolled, or they would blind filter bags fairly quickly, resulting in unacceptable pressure drops and requiring impossibly frequent bag replacement.
ESPs rely on the ability of a particle to acquire an electrical charge. Once charged, the particles migrate from the flue gas to oppositely charged plates where they deposit. The deposits are removed by rapping the plates and they settle by gravity to collection hoppers. The organic nature of the ultra-fine particulates generated by gaseous fuel combustion is such that acquiring the necessary electrical charge is difficult. ESPs also rely on gravity settling of the collected particulates. The fine particles produced in gas-fired boilers are such that gravity settling is unlikely to occur and any particles collected on the plates would likely be re-entrained in the flue gas as the plates are rapped.

The top-performing feasible $PM/PM_{10}/PM_{2.5}$ control technology is the firing of 100% purchased natural gas in the boiler, because the very low sulfur content of natural gas will result in low condensable PM_{10} and $PM_{2.5}$ emissions relative to the use of refinery fuel gas. The next most effective technically feasible $PM/PM_{10}/PM_{2.5}$ control option is the use of good combustion practices in combination with firing gaseous fuels.

The calculated cost of firing 100% purchased natural gas, per ton of PM_{10} or $PM_{2.5}$ reduced as a result, is greater than $1 million/ton PM_{10} or $PM_{2.5}$ based on a natural gas price of approximately $5/MMbtu. As such, this option is not considered cost effective and is rejected as BACT.

Consistent with all $PM/PM_{10}/PM_{2.5}$ BACT determinations for refinery fuel gas fired sources found in the RBLC, proper design and good combustion techniques constitute $PM/PM_{10}/PM_{2.5}$ BACT for the retrofit boiler.

The control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

IV. Emission Inventory

The following table summarizes the potential to emit for Boiler #10 after the retrofit with lower NO_x burners:

Unit	**Annual Emissions (TPY)**				
	NO_x	**CO**	**VOC**	**$TSP/PM_{10}/PM_{2.5}$**	**SO_2**
Boiler #10, after retrofit	13.14	21.90	2.23	3.50	4.14
Totals:	**13.14**	**21.90**	**2.23**	**3.50**	**4.14**

Boiler capacity = 99.9 MMBtu-HHV/hr
Hours of Operation = 8,760 hrs/yr
Fuel Heating Content = 1,072 Btu/scf for refinery fuel gas

<u>NO_x Emissions:</u>

0.03 lb/MMBtu-HHV (vendor guarantee)

0.03 lb/MMBtu-HHV * 99.9 MMBtu-HHV/hr * 8,760 hr/yr * 1 ton/2,000 lb = 13.14 TPY

CO Emissions:
0.052 lb/MMBtu-HHV (vendor guarantee)
0.052 lb/MMBtu-HHV * 99.9 MMBtu-HHV/hr * 8,760 hr/yr * 1 ton/2,000 lb = 21.90 TPY
VOC Emissions:
5.5 lb/MMscf (AP-42, 1.4-6, 7/98)

5.5 lb/MMscf * 1 scf/1,072 Btu * 99.9 MMBtu/hr * 8,760 hr/yr * 1 ton/2,000 lb = 2.23 TPY

TSP/PM_{10}/$PM_{2.5}$ Emissions:
0.008 lb/MMBtu-HHV (vendor guarantee)

0.008 lb/MMBtu-HHV * 99.9 MMBtu-HHV/hr * 8,760 hr/yr * 1 ton/2,000 lb = 3.50 TPY

SO_2 Emissions:
60 ppmv H_2S in fuel gas, 365-day rolling average (NSPS Subpart Ja, assuming 100% conversion of H_2S to SO_2).

60 ppm H_2S * 99.9 MMBtu/hr * 1 scf/1,072 Btu * 1 lb-mol H_2S/379 scf H_2S * 34 lb H_2S/lb-mol H_2S * 64 lb SO_2/34 lb H_2S * 8,760 hr/yr * 1 ton/2,000 lb = 4.14 TPY

V. Existing Air Quality

There are two areas in Billings (approximately 12 miles northeast of the CHS Refinery) which were federally designated nonattainment for CO (National Ambient Air Quality Standards (NAAQS)) and for the old secondary total suspended particulates (PM) standard. EPA redesignated the Billings CO nonattainment area to attainment on April 22, 2002. The old PM standard has since been revoked and replaced with new PM_{10} (respirable) standards. The Billings area is listed as not classified/attainment for the new 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, plants operating at less than full capacity, and industrial process changes to meet sulfur in fuel regulations. Ambient air quality monitoring for SO_2, PM_{10}, and CO in the Billings/Laurel area continues.

VI. Air Quality Impacts

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

VII. 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
1520 East Sixth Avenue
P.O. Box 200901, Helena, Montana 59620-0901
(406) 444-3490

FINAL ENVIRONMENTAL ASSESSMENT (EA)

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

Permit Number: 1821-20

Preliminary Determination on Permit Issued: 9/22/09
Department Decision Issued: 10/09/09
Permit Final: 10/27/09

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

2. *Description of Project*: The Department received a complete application from CHS on August 13, 2009, requesting a modification to MAQP #1821-19. CHS is proposing 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 is being completed on a voluntary basis by CHS to improve environmental performance and boiler reliability. It is expected that actual utilization of this boiler may increase following completion of the project.

3. *Objectives of Project*: To improve environmental performance and reliability of Boiler #10.

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

5. *A listing of mitigation, stipulations and other controls*: A list of enforceable permit conditions and a complete permit analysis, including a BACT determination, would be contained in MAQP #1821-20.

6. *Regulatory effects on private property*: The Department considered alternatives to the conditions imposed in this permit as part of the permit development. The Department determined that the permit conditions are reasonably necessary to ensure compliance with applicable requirements and to demonstrate compliance with those requirements and do not unduly restrict private property rights.

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

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

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

A. Terrestrial and Aquatic Life and Habitats:

This permitting action would result in increased NO_x, SO_2, VOC, and PM emissions. However, the emissions are within the facility-wide emissions caps established in MAQP #1821-05 in 2000. Impacts to terrestrial life and habitats may occur as a result of these increased emissions. Habitat impacts could result in a change of diversity or abundance of terrestrial or aquatic life. However, this area does not appear to contain any critical or unique wildlife habitat or aquatic life and the project would occur in an already disturbed area. Therefore, only minor impacts to terrestrial and aquatic life and habitats are anticipated.

B. Water Quality, Quantity, and Distribution:

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

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

No additional disturbance would be created from this permitting action. The proposed project would involve an existing piece of equipment. This permitting action would not change the soil stability or geologic substructure or result in any increased disruption, displacement, erosion, compaction, or moisture loss, which would reduce productivity or fertility at or near the site. No unique geologic or physical features would be disturbed. Therefore, no impacts to geology and soil quality, stability, and moisture are anticipated.

D. Vegetation Cover, Quantity, and Quality:

This project would involve the retrofit of Boiler #10, an existing piece of equipment. This equipment is located in an industrial site that is generally free of vegetative cover. As such, the vegetative cover, quantity, and quality would not be disturbed inside the facility boundaries. However, possible increases in actual emissions of NO_x, SO_2, PM, and VOC from historical emission levels may result in minor impacts to the diversity, productivity, or abundance of plant species in the surrounding areas. Issuance of this permit would cause minor, if any, changes in vegetation cover, quantity, or quality.

E. Aesthetics:

This project would be constructed on land already used for industrial activities, and would not result in any additional disturbance. Noise levels would not be expected to change as a result of this project. Therefore, no additional impacts on aesthetics are expected.

F. Air Quality:

The project would include increases of NO_x, SO_2, PM, and VOC emissions above recent historical levels. However, the emissions are within the facility-wide emissions caps established in MAQP #1821-05 in 2000. Previously modeled levels of pollutants (at allowable levels) show compliance with the NAAQS and the MAAQS. The overall impact on air quality would be expected to be minor.

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

This permitting action may result in minor impacts to unique endangered, fragile, or limited environmental resources. However, the Department is not aware of any unique, rare, threatened, or endangered species in the area surrounding the facility. Further, as described in Section 7.F. of this EA, pollutant emissions generated from the facility would have minimal impacts on air quality in the immediate and surrounding area because of the relatively small amount of pollution emitted. There would not be any additional impact to these resources because the project would occur at an already disturbed site.

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

This project would not consume any significant additional energy or water resources. Further, as described in Section 7.F. of this EA, pollutant emissions generated would have minimal impacts on air quality in the immediate and surrounding area. Previous modeling efforts, using allowable levels, showed compliance with the NAAQS and the MAAQS. This project would result in a minor effect on the air resource, but resulting emissions will still comply with ambient air quality standards.

I. Historical and Archaeological Sites:

This project would not disturb a greater land surface than has already been occupied by the refinery. This project would occur within the boundaries of the area already disturbed. Therefore, no impacts to any historical and archaeological sites would be anticipated.

J. Cumulative and Secondary Impacts:

Increases in actual pollutant emissions above historical levels may result in minor cumulative and secondary impacts to terrestrial and aquatic habitats, water quality, and air quality. However, as previously mentioned, the emissions are within the facility-wide emissions caps established in MAQP #1821-05 in 2000. Minor cumulative or secondary impacts are expected to result from this project.

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

B. Cultural Uniqueness and Diversity:

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

C. Local and State Tax Base and Tax Revenue:

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

D. Agricultural or Industrial Production:

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

E. Human Health:

As described in Section 7.F of the EA, the impacts from this facility on air quality would be minor. The project would include increases in NO_x, SO_2, PM, and VOC emissions from recent emissions levels. However, the emissions are within the facility-wide emissions caps established in MAQP #1821-05 in 2000. The air quality permit for this facility incorporates conditions to ensure that the facility would be operated in compliance with all applicable rules and standards. These rules and standards are designed to be protective of human health. Therefore, only minor impacts to human health would be expected from this project.

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

This project would not have an impact on recreational or wilderness activities because the site is far removed from recreational and wilderness areas or access routes. This project would not result in any changes in access to and quality of recreational and wilderness activities.

G. Quantity and Distribution of Employment:

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

H. Distribution of Population:

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

I. Demands of Government Services:

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

J. Industrial and Commercial Activity:

The refinery's overall capacity would not change as a result of the proposed project. Therefore, no impacts on industrial activity at CHS would be expected. Industrial and commercial activity in the neighboring area is not anticipated to be affected by issuing MAQP #1821-20.

K. Locally Adopted Environmental Plans and Goals:

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

L. Cumulative and Secondary Impacts:

Increases in actual pollutant emissions of NO_x, SO_2, PM, and VOC above recent historical levels may result in minor cumulative and secondary impacts to the human environment. However, the emissions are within the facility-wide emissions caps established in MAQP#1821-05 in 2000. Therefore, the cumulative and secondary impacts from the proposed project would 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: Moriah Thunstrom
Date: 9/16/2009