

**MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY
OPERATING PERMIT TECHNICAL REVIEW DOCUMENT**

**Permitting and Compliance Division
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CHS, Inc.
Laurel Refinery
802 South Highway 212
P.O. Box 909
Laurel, Montana 59044-0909

The following table summarizes the air quality programs testing, monitoring, and reporting requirements applicable to this facility.

Facility Compliance Requirements	Yes	No	Comments
Source Tests Required	X		Methods 5/5B/5F (PM) Methods 6/6C (SO ₂) Method 7 (NO _x) Method 9 (opacity) Method 10 (CO) Method 11 (H ₂ S) Method 18 (VOC)
Ambient Monitoring Required		X	
COMS Required	X		FCC Regenerator
CEMS Required	X		SO ₂ , H ₂ S, NO _x , CO
Schedule of Compliance Required		X	
Annual Compliance Certification and Semiannual Reporting Required	X		
Monthly Reporting Required		X	
Quarterly Reporting Required	X		
Applicable Air Quality Programs			
ARM Subchapter 7 Montana Air Quality Permits (MAQP)	X		MAQP #1821-22
New Source Performance Standards (NSPS)	X		40 CFR 60, Subpart A, Subpart J, Subpart Ja, Subpart Db, Subpart Kb, Subpart UU, Subpart GGG, Subpart GGGa, Subpart QQQ
National Emission Standards for Hazardous Air Pollutants (NESHAPS)	X		40 CFR 61, Subpart FF
Maximum Achievable Control Technology (MACT)	X		40 CFR 63, Subpart R, Subpart CC, Subpart UUU, Subpart ZZZZ
Major New Source Review (NSR) – includes Prevention of Significant Deterioration (PSD) and/or Non-attainment Area (NAA) NSR	X		
Risk Management Plan Required (RMP)	X		
Acid Rain Title IV		X	
Compliance Assurance Monitoring (CAM)		X	
State Implementation Plan (SIP)	X		Billings/Laurel SO ₂ Control Plan

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SECTION I. GENERAL INFORMATION

A. Purpose

This document establishes the basis for the decisions made regarding the applicable requirements, monitoring plan, and compliance status of emission units affected by the operating permit proposed for this facility. The document is intended for reference during review of the proposed permit by the U.S. Environmental Protection Agency (EPA) and the public. It is also intended to provide background information not included in the operating permit and to document issues that may become important during modifications or renewals of the permit.

Conclusions in this document are based on information provided in the original application submitted to the Montana Department of Environmental Quality Air Resources Management Bureau (Department) by Cenex Harvest States Cooperatives (Cenex) on 07/10/95, the application for renewal submitted by CHS, Inc. (CHS) on May 12, 2006, and the significant modification applications submitted by CHS on October 10, 2007; February 25, 2008; November 7, 2008; February 27, 2009; and April 1, 2010 (determined to be substantively and technically complete on April 22, 2010).

B. Facility Location

The CHS-Laurel Refinery is located at the South ½, Section 16, Township 2 South, Range 24 East, Yellowstone County. This legal description refers to a physical address of 802 South Highway 212, Laurel, Montana.

C. Facility Background Information

Montana Air Quality Permit History

On May 11, 1992, Cenex was issued **Montana Air Quality Permit (MAQP) #1821-01** for the construction and operation of a hydro-treating process to desulfurize Fluidized Catalytic Cracking Unit (FCCU) 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 FCCU feeds by removing metal, nitrogen, and sulfur compounds from these feeds. The proposed HDS unit also improved the quality of refinery finished products including gasoline, kerosene, and diesel fuel. The HDS project significantly improved the finished product quality by reducing the overall sulfur contents of liquid products from the Cenex Refinery. The HDS unit provided low sulfur gas-oil feedstocks for the FCCU, which resulted in major reductions of sulfur oxide emissions to the atmosphere. However, only a minor quantity of the proposed sulfur dioxide (SO₂) emission reductions were 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 emission increase that was less than the significant level of 40 tons per year for SO₂ and oxides of nitrogen (NO_x). The application referred to significant SO₂ emission reductions that were expected by addition of the HDS project. These anticipated major SO₂ reductions were not committed to by Cenex under federally enforceable permit conditions and

limitations. The contemporaneous emission decreases for SO₂ and NO_x, which were made federally enforceable under this permitting action, amount to approximately 15.5 and 23.7 tons per year, respectively. Construction of the HDS/sulfur recovery complex was completed in December 1993, and the 180-day shakedown period ended in June 1994.

MAQP #1821-02 was issued on February 1, 1997, to authorize the installation of an additional boiler (#10 Boiler) to provide steam for the facility. Cenex submitted the original permit application for a 182.50-million British thermal unit per hour (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 had not been identified; however, the boiler was to be rated at approximately 80,000 pounds (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, also applied as of November 1, 1997. Increases in emissions from the new boiler were detailed in Section IV of the permit analysis for MAQP #1821-02. Modeling performed showed that the emissions increase would not result in a significant impact to the ambient air quality (see Section VI of the permit analysis).

Cenex also requested a permit alteration to remove the SO₂ emission limits (Section II.E.2.a of MAQP #1821-01) for the C-201B compressor engine because the permit already limits C-201B to be fired on either natural gas or unodorized propane. Cenex also requested that if the SO₂ emission limits could not be removed, the limits should be corrected to allow for the combustion of natural gas and propane. The Department altered the permit to allow for burning odorized propane in the C-201B compressor.

Cenex also requested a permit modification to change the method of determining compliance with the HDS Complex emitting units. MAQP #1821-01 required 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 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 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 agreed that actual stack testing data is preferred to manufacturer's data for the development of emission factors. However, the Department required that the emission factor be developed from the most recent source test and not on an average of previous source tests. The permit was 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.

This permit (#1821-02) was written to maintain the language from the HDS Complex MAQP #1821-01, where possible, and to separate the HDS Complex MAQP #1821-01 requirements from the requirements for the current action (Boiler #10). The permit requirements from MAQP #1821-01 were included in MAQP #1821-02.

On June 4, 1997, Cenex was issued **MAQP #1821-03** to modify emissions and operational limitations on components in the Hydrodesulfurization Complex at the Laurel refinery. The unit was originally permitted in 1992, but has not been able to operate adequately under the emission 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
H-201 (cont.)	CO	4.86 ton/yr	8.89 ton/yr
		1.40 lb/hr	2.23 lbs/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 was 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 was now proposing. Because of this, the permit action and the original permitting of the HDS had to be considered one project in order to determine the permitting requirements. When combined with the original permitting of the HDS, the emission increases of NO_x and SO₂ would exceed significant levels and subject this action to the requirements of the NSR/PSD program. During the original permitting of the HDS complex, Cenex chose to “net out” of NSR and PSD review by accepting limitations on the emissions of NO_x and SO₂ from the old sour water stripper (SWS). Because of the emission increases proposed in this permitting action, additional emission reductions had to occur. Cenex proposed additional reductions in emissions from the old SWS to offset the increases allowed by this permitting action. These limitations would reduce the “net emissions increase” to less than significant levels and negate the need for review under the NSR/PSD program. The new emission limits for SO₂ and NO_x from the old SWS are 290.9 and 107.9 tons/year, respectively.

This permitting action also removed the emission limits and testing requirements for particulate matter less than 10 microns (PM₁₀) on the HDS Heaters (H-101, H-201, and H-202). These heaters combust refinery gas, natural gas and PSA gas. The Department determined that potential PM₁₀ emissions from these fuels were minor and that emission limits and the subsequent compliance demonstrations for this pollutant were unnecessary. Also removed from this permit were the compliance demonstration requirements for SO₂ and volatile organic compounds (VOCs) when the combustion units are firing natural gas. The Department determined that firing the units solely on natural gas would, in itself, demonstrate compliance with the applicable limits.

This action would result in an increase in allowable emissions of VOC and carbon monoxide (CO) by 4.7 ton/yr and 60 ton/yr, respectively. Because of the offsets provided by reducing emissions from the old SWS, this permitting action would not increase allowable emissions of SO₂ or NO_x from the facility.

The following changes were made to the Department’s preliminary determination (PD) in response to comments from Cenex.

1. The emission limits for the old SWS in Section II.D.2 were revised to ensure that the required offsets were provided without putting Cenex in a non-compliance situation at issuance of the permit. The compliance determinations of Section II.G.5 and the reporting requirements of Section II.H.1.d were also changed to reflect this requirement.

2. The CO emission limits for H-201 in Section II.D.6 were revised; the old limits were inadvertently left in the PD. The table in Section I.B of the analysis was also changed to reflect this.
3. 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.
4. Section F of the General Conditions was removed because the Department had placed the applicable requirements from the permit application into the permit.
5. Numbering had been changed in Section III.

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

The product loading rack was 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 consisted of three arms, each with a capacity of 500 gallons per minute (gpm). However, only two loading arms were 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 was defined as an incinerator under MCA 75-2-215, a determination that the emissions from the VCU would constitute a negligible risk to public health was required prior to the issuance of a permit to the facility. Cenex and the Department identified the following hazardous air pollutants from the flare, which were used in the health risk assessment. These constituents are typical components of Cenex's gasoline.

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

The reference concentration for Benzene was obtained from EPA's IRIS database. The ISCT3 modeling performed by Cenex, for the hazardous air pollutants identified above, demonstrated compliance with the negligible risk requirement.

On September 3, 2000, **MAQP #1821-05** was issued to Cenex to revamp its No. 1 Crude Unit in order to increase crude capacity, improve product quality, and enhance energy recovery. The proposed project involved the replacement and upgrade of various heat exchangers, pumps, valves, towers, and other equipment. Only VOC emissions would be affected by the proposed 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 proposed project actually decreased 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 may 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 allowed emission increases to remain below the applicable significant modification thresholds that trigger the NSR program for PSD and Nonattainment Area (NAA) permitting.

The site-wide limits were calculated based on the addition of the PSD/NAA significance level for each particular pollutant to the actual refinery emissions from April 1998, through March 2000, for SO₂, NO_x, CO, PM₁₀, and total suspended particulate (TSP) 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
TSP	April 1998-March 2000	137.3	25	162.2

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

Average refinery-wide SO₂ emissions in the period of April 1998 through 2000, added to the PSD/NAA significance level for SO₂ minus 0.1 tpy =

$$2940.4 \text{ tpy} + 40 \text{ tpy} - 0.1 \text{ tpy} = 2980.3 \text{ tpy} = \text{Annual emissions cap.}$$

MAQP #1821-05 replaced MAQP #1821-04. This was the last permitting action for the initial Title V Operating Permit #OP1821-00.

MAQP #1821-06 was issued on April 26, 2001, for the installation and operation of eight temporary, portable Genertek reciprocating engine electricity generators and two accompanying distillate fuel storage tanks. Each generator is capable of generating approximately 2.5 megawatts of power. These generators are necessary because of the high cost of electricity. The operation of the generators will not occur beyond 2 years and is not expected to last for an extended period of time, but rather only for the length of time necessary for Cenex to acquire a more economical supply of power.

Because these generators would only be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of these generators is minor. In addition, the installation of these generators qualifies as a “temporary source” under the PSD permitting program because the permit will limit the operation of these generators to a time period of less than 2 years. Therefore, Cenex would not need to comply with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, the Department required compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 would be ensured. In addition, Cenex would be responsible for complying with all applicable air quality standards. In order to keep this permitting action below the threshold of nonattainment area permitting requirements, Cenex requested a limitation to keep the project’s potential emissions of SO₂ below 40 tons. MAQP #1821-06 replaced MAQP #1821-05.

MAQP #1821-07 was issued on August 28, 2001, to change the wording in Section VII.A.2, 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 (ARM 17.8.315), to correct conditions improperly referencing the incinerator rule (ARM 17.8.316), and to update a testing frequency on the product loading rack VCU based on the Title V permit term. MAQP #1821-07 replaced MAQP #1821-06.

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

On March 13, 2003, the Department received a complete MAQP 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 Tail Gas Treatment Unit (TGTU) for both the Sulfur Recovery Unit (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 MAQP Application from CHS to modify MAQP #1821-09. The application was complete with the addition of modeling information provided to the Department on August 22, 2003. CHS requested to add a new TGTU and associated equipment for Zone A's SRU #1 and SRU #2 trains to control and reduce SO₂ emissions from this source. CHS submitted modeling to the Department for a determination of a minimum stack height for the existing SRU #1 and SRU #2 tail gas incinerator stack. CHS also submitted a letter to the Department to change the name on the permit from Cenex to CHS. The permit action added the new TGTU, set a minimum stack height for the tail gas incinerator stack, and changed the name on the permit from Cenex to CHS. **MAQP #1821-10** replaced MAQP #1821-09.

On June 1, 2004, the Department received two MAQP 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/Tail Gas Incinerator (TGI), Naphtha Hydrotreating (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 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 NSR analysis. The net emission changes were as follows:

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

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

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

NHT Charge Heater: 13.2 to 20.1 MMBtu-LHV/hr (22.1 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 “*Naphtha Hydrotreating Unit*”; Section D.1.c is based on a 30-day rolling average; Section X.D.7.a.ii should state that the SO₂ limit is based on a 12-hour average; and that Section XI.E.3 should be revised to remove the requirement for a stack gas volumetric flow rate monitor. The Department made some clarifications to the language in Section X.D.6.b. The Department’s intent in permitting the coke pile with enclosures was to ensure that at no time would the coke pile be higher than the top of the enclosure walls at any point on the pile, not only the portion of the pile that is adjacent to the wall.

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

The Department received comments from CHS on the preliminary determination of **MAQP #1821-14** on June 21, 2006. The comments were editorial in nature and the changes were made prior to issuance of the Department Determination on MAQP #1821-14. CHS requested corrections to the PM, PM₁₀, NO_x netting values in Section II.G of 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 include:

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

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

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

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

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

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

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

On February 25, 2008, the Department received a complete application from CHS to modify MAQP #1821-16 for the completion of two separate projects. For the first project, CHS proposed to construct a new 209.1 MMBtu-HHV/hr steam generating boiler (Boiler #12). This project includes the permanent shutdown of two existing boilers, Boilers #4 and #5, which have a combined capacity of 190 MMBtu-LHV/hr. The two existing boilers are being shutdown in part to meet the consent decree NO_x reduction requirements, as well as to generate NO_x offsets for this permitting action.¹ Due to the operational complexity of replacing two existing boilers with one new boiler in the refinery steam system, CHS requested to maintain the ability to operate the #5 Boiler for 1 year after initial start-up of Boiler #12. Combustion of fuel oil in the refinery boilers would also be eliminated primarily to generate NO_x offsets for this permitting action.

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

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

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

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

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

On April 1, 2008, CHS requested that the Department delay issuance of the preliminary determination for this permit application until additional information could be submitted regarding alternative coke handling practices. This additional information was submitted to the Department on April 3, 2008, with follow-up information received by the Department on April 14, 2008. CHS requested that an alternative coke handling process be included in MAQP #1821-17. The coke handling process, originally permitted

as part of the delayed coker project, included the use of conveyors to transport coke to a crusher and to a railcar loading system. Because the system is enclosed, it is not possible to transport coke to the crusher and loading system without the use of the conveyors. CHS has since identified the need for an alternate coke handling method to be used when the conveyors are out of operation for either planned or unplanned maintenance. MAQP #1821-17 replaced MAQP #1821-16.

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

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

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

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

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

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

On August 13, 2009, the Department received a complete application from CHS requesting a modification to MAQP #1821-19. CHS proposed to retrofit the existing Boiler #10 with a lower NO_x control technology burner and to update the permit limits for this unit accordingly. This project was completed on a voluntary basis by CHS in order to improve environmental performance and boiler reliability. On September 17, 2009, the Department received a revision to this application addressing the SO₂ BACT analysis for both Boiler #10 and the recently permitted Platformer Splitter Reboiler. This application revision was submitted in consultation with the Department and revised the SO₂ BACT analysis to reflect the recently finalized NSPS Subpart Ja requirements. **MAQP #1821-20** replaced MAQP #1821-19.

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

During the issuance of MAQP #1821-17, it became apparent that the Department and CHS had differing interpretations of paragraphs 177 and 180 of the CHS Consent Decree (CD) with EPA and the State of Montana (Consent Decree CV-03-153-BLG-RFC). Based on these differing interpretations, CHS deemed it necessary to retroactively analyze previous permit actions, particularly associated with the Delayed Coker Project, where changes may be necessary as a result of interpreting the CD in an alternative manner. On October 26, 2009, CHS provided an analysis concluding that the Delayed Coker Project was properly permitted as a non-major modification under New Source Review (including both PSD and Non-attainment Area New Source Review (NNSR)). For four pollutants (CO, VOC, TSP, and PM-10), project related emissions increases determined under Step 1 of the required applicability analysis were below the applicable significance thresholds. For two pollutants (NO_x and SO₂), the net emissions change, including project related emissions increases and contemporaneous emissions changes, were below the applicability significance thresholds. Following review, the Department concurred with CHS' analysis. However, as a result of this re-examination, including updates and changes to the original Delayed Coker Project emissions calculations, the following updates to MAQP #1821-20 were necessary to accurately reflect the refinery's overall process and individual emitting units.

1. Coke Drum Steam Vent

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

2. FCCU Regenerator

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

3. Boiler 12 and Railcar Light Product Loading Projects

Originally permitted within MAQP #1821-17, the Boiler 12 and Railcar Light Product Loading Projects were included in the same permit application for administrative convenience only and should not be included as part of the Delayed Coker Project's

emissions increase calculations. The Department agrees that the two projects were not substantially related and had no apparent interconnection to each other or to the Delayed Coker Project. The emissions calculations were updated to reflect this conclusion.

4. Shutdown Timing for #4 and #5 Boilers

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

5. Benzene Reduction Unit Project Updates

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

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

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

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

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

Title V Operating Permit History

CHS's Title V **Operating Permit #OP1821-00** was issued final & effective on November 11, 2001.

On May 12, 2006, the Department received an application for the renewal of Title V Operating Permit #1821-00. The application was deemed administratively complete on June 12, 2006 and technically complete on July 11, 2006. Permit #OP1821-01 incorporates all applicable source changes since the issuance of Permit #OP1821-00, including:

- Addition of three new emitting units: #EU021 (ULSD and Hydrogen Plant), #EU022 (Delayed Coker Unit), and #EU023 (Zone E SRU and TGTU);
- Incorporation of Consent Decree CV-03-153-BLG-RFC requirements. This included updating the Title V Operating Permit with a number of specific new emission limits and monitoring requirements which had been included in the most recent MAQP #1821-15, as well as adding a general requirement for CHS to comply with the relevant applicable terms and conditions of the Consent Decree (most importantly, the Affirmative Relief/Environmental Projects, Subsections A-M, (excluding the stipulated penalty components)); and
- Inclusion of new regulations impacting CHS, including three MACT standards: 40 CFR 63, Subpart UUU, Subpart ZZZZ, and Subpart DDDDD.

On October 4, 2007, CHS appealed Operating Permit #OP1821-01 on the basis of the inclusion of the entire Consent Decree CV-03-153-BLG-RFC. CHS' contention was that ARM 17.8.1211(2) only allows consent decree requirements to be included that are as a result of non-compliance with a specific rule or regulatory requirement. The Department included the Consent Decree because it considered the Consent Decree requirements as relevant terms and conditions required to be included in the Title V Operating Permit. The following language (and changes to the permit as described below) satisfy both CHS and the Department with respect to inclusion of Consent Decree requirement into the Title V Operating Permit:

“CHS has entered into a Consent Decree (United States et al v. CHS Inc., Civil Action CV-03-153-BLG-RFC (D. Mont. February 23, 2004)). Certain consent decree emission limits, standards, and schedules have been incorporated as term and conditions of the permit, into the appropriate sections of this permit. Other consent decree requirements are considered program enhancements and are not included as terms or conditions of the permit. These requirements, found in Appendix F of the permit, may be enforced by the State of Montana and the United States Environmental Protection Agency pursuant to the provisions of the consent decree.”

Operating Permit #OP1821-01 replaced Operating Permit #OP1821-00.

On October 10, 2007; February 25, 2008; November 7, 2008; and February 27, 2009, the Department received significant modification applications from CHS. The significant modifications included:

- An increase in the firing rate of the NHT Charge Heater (H-8301) to address an operating scenario that was overlooked during the delayed coker unit design process (#OP1821-02);
- The installation of a new steam generating boiler (Boiler #12), expansion of the existing railcar light product loading facilities, as well as an alternative coke handling practice (#OP1821-03);
- The construction of a Benzene Reduction Unit to comply with the Mobile Source Air Toxics Rule (#OP1821-04); and
- Clarification of the averaging period applicable to the Boiler #12 NO_x permit limit (#OP1821-05).

All of these significant modifications were issued under Operating Permit #OP1821-05. **Operating Permit #OP1821-05** replaced Operating Permit #OP1821-01.

D. Current Permit Action

The current permit action incorporates recent MAQP actions taken as a result of the following applications and supplemental information:

- August 13, 2009: CHS proposed retrofitting the existing Boiler #10 with a lower NO_x control technology burner and to update the permit limits for this unit accordingly. This project was completed on a voluntary basis by CHS in order to improve environmental performance and boiler reliability.
- September 17, 2009: This information comprised of a revision to the August 13, 2009 application addressing the SO₂ BACT analysis for both Boiler #10 and the recently permitted Platformer Splitter Reboiler. This application revision was submitted in consultation with the Department and revised the SO₂ BACT analysis to reflect the recently finalized NSPS Subpart Ja requirements.

(These modifications would have been issued under Operating Permit #OP1821-06; however, were combined with the two modification requests that follow.)

- March 31, 2010: CHS proposed modifications associated with the results of retroactively analyzing previous permit actions, particularly associated with the Delayed Coker Project. This application and additional information included requests for several modifications within the permit. These requests have been outlined above within the Montana Air Quality Permit history outlining the changes that resulted in MAQP #1821-21.
- July 27, 2010: This administrative amendment request constituted of the addition of ppmvd units where H₂S limits are expressed in gr/dscf and also including the December 31, 2010 shutdown date for Boiler #4 and Boiler #5.

Operating Permit #OP1821-07 replaces Operating Permit #OP1821-05

E. Taking and Damaging Analysis

HB 311, the Montana Private Property Assessment Act, requires analysis of every proposed state agency administrative rule, policy, permit condition or permit denial, pertaining to an environmental matter, to determine whether the state action constitutes a taking or damaging of private real property that requires compensation under the Montana or U.S. Constitution. As part of issuing an operating permit, the Department is required to complete a Taking and Damaging Checklist. As required by 2-10-101 through 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.

F. Compliance Designation

On September 29, 2006, CHS was inspected by the Department and found to be in compliance with applicable requirements. Since that time, however, the Department has initiated an enforcement action against CHS for Boiler #10 NO_x violations. These violations were addressed through an administrative order on consent requiring CHS to pay a penalty of \$165,000. On April 7, 2009, the Department received the full and final payment of the administrative penalty in accordance with the consent order. With the receipt of this payment, the Department considered the enforcement action resolved.

SECTION II. SUMMARY OF EMISSION UNITS

A. Facility Process Description

CHS is a petroleum refinery located in Laurel, Montana. The refining process distills crude oil using heat. This distillation separates the crude oil into its component parts. The refiner then cracks some of the heavier molecules by applying heat in the presence of a catalyst to make the reaction take place. These raw products are then treated in several ways to take out impurities. Finally, the proper liquids and additives are blended to create the desired product. The major processing equipment includes:

1. Atmospheric and vacuum crude distillation towers
2. Naphtha Hydrotreaters (NHT) (*previously Unifiners*)
3. Platformer (= Naphtha Reformer)
4. Fluidized Catalytic Cracking (FCC) Unit
5. Alkylation/Butamer/Merox/Saturate Units
6. Hydrodesulfurization (HDS) Unit and Hydrogen Plant
7. Four Sulfur Recovery Units (SRUs) with Tailgas Treatment Units (TGTUs)
8. Ultralow Sulfur Diesel Unit and Hydrogen Plant
9. Delayed Coker Unit
10. Benzene Reduction Unit
11. Transfer Facilities (Truck Product Loading, Railcar Product Loading)

B. Emission Units and Pollution Control Device Identification

Emission Unit ID	Description	Pollution Control Device/Practice
EU001	Plant-wide and Multiple Emitting Unit Limitations	Permit #1821-05 Limits, Billings/ Laurel SO ₂ Stipulation, and MACT LDAR program, where applicable. CEMS on Refinery Fuel Gas Header(s).
EU002	#1 Crude Unit and Naphtha Splitter <ul style="list-style-type: none"> • #1 Crude Unit Preheater (CV-HTR-1) • #1 Crude Unit Main Heater (CV-HTR-2) • #1 Crude Unit Vacuum Heater (CV-HTR-4) 	LDAR, Billings/ Laurel SO ₂ Stipulation
EU003	#2 Crude Unit <ul style="list-style-type: none"> • #2 Crude Unit Main Heater (2CV-HTR-1) • #2 Crude Unit Vacuum Heater (2CV-HTR-2) 	LDAR, Billings/ Laurel SO ₂ Stipulation
EU004	PDA Unit – <i>SHUTDOWN</i>	
EU005	Naphtha Hydrotreater Unit <ul style="list-style-type: none"> • NHT Charge Heater (H-8301) • NHT Reboiler Heater #1 (H-8302) • NHT Reboiler Heater #2 (H-8303) • NHT Splitter Reboiler Heater (H-8304) 	LDAR, Billings/ Laurel SO ₂ Stipulation
EU006	Middle Distillate Unifiner – <i>SHUT DOWN</i>	
EU007	Platformer Unit <ul style="list-style-type: none"> • Platformer Heater (P-HTR-1) • Platformer Debutanizer Reboiler Heater (P-HTR-2) • Platformer Splitter Reboiler (P-HTR-3) • Platformer Recycle Compressor Turbine (C-4772) 	LDAR, Billings/ Laurel SO ₂ Stipulation, Low NO _x technology (Platformer Heater and Platformer Splitter Reboiler)

EU008	Fluid Catalytic Cracking (FCC) Unit <ul style="list-style-type: none"> FCC Charge Heater (FCC-Heater-1) FCC Regenerator (FCC-VSSL-1) 	LDAR, SO ₂ CEMS, Billings/ Laurel SO ₂ Stipulation
EU009	Alkylation/Butamer/Merox/Saturate Units <ul style="list-style-type: none"> Alkylation Unit Hot Oil Belt Heater (ALKY-HTR-1) Miscellaneous Process Vent (Alkylation Unit Butamer Stabilizer Offgas) 	LDAR, Billings/ Laurel SO ₂ Stipulation
EU010	Hydrodesulfurization Unit and Hydrogen Plant (100 Unit) <ul style="list-style-type: none"> Reformer Heater (H-101) Reactor Charge Heater (H-201) Fractionator Feed Heater (H-202) Hydrogen Compressor Gas Engine (C-201B) 	LDAR, Permit #1821-05 Limits, Low NO _x Technology (on heaters), Billings/ Laurel SO ₂ Stipulation
EU011	Zone D Sulfur Recovery Unit (SRU) and Tail Gas Treatment Unit (TGTU) <ul style="list-style-type: none"> SRU Reheater (E-407) Incinerator (INC-401) 	Permit #1821-05 Limits, Low NO _x Technology, SO ₂ CEMS, Billings/ Laurel SO ₂ Stipulation
EU012	Zone A SRU and TGTU <ul style="list-style-type: none"> #1 SRU Incinerator (SRU-AUX-4) 	SO ₂ CEMS, Billings/ Laurel SO ₂ Stipulation
EU013	Steam Generation Units <ul style="list-style-type: none"> #1 Fuel Oil Heater (CV-HTR-9) #4 Boiler #5 Boiler #9 Boiler Boiler #10 Boiler #11 Boiler #12 	Permit #1821-05 Limits Fuel Oil Flow Meters (#3, #4, #5 Boilers) LDAR and Low NO _x Technology (Boilers #10, #11, and #12), Billings/ Laurel SO ₂ Stipulation
EU014	Tank Farm (non-Wastewater): <ul style="list-style-type: none"> MACT Group 1 Storage Vessels MACT Group 2 Storage Vessels Exempt – pressure vessels Exempt – not organic HAP Exempt – not refining 	Internal and External Floating Roofs, Fixed Roofs, LDAR (as applicable), Billings/ Laurel SO ₂ Stipulation
EU015	Transfer Facilities <ul style="list-style-type: none"> Asphalt Loading Heater #1 Truck Product Loading Rack Vapor Combustion Unit (VCU) Railcar Product Loading Rack VCU 	VCU on Light Product Truck Loading Rack and Railcar Loading Rack LDAR, Billings/ Laurel SO ₂ Stipulation
EU016	Wastewater Treatment Units <ul style="list-style-type: none"> Wastewater Treatment Unit (old) Wastewater Treatment Unit (new) Tanks: Tank 23, Tank 25, Tank 44, Tank 118, Tank 119, Tank 128, and Tank 129 New Wastewater Treatment Unit Vessels Benzene Reduction Unit Oily Water Sewer 	Enclosed conveyance and other wastewater controls for affected equipment per NSPS QQQ; Floating roofs per NSPS Kb
EU017	Flare Systems <ul style="list-style-type: none"> Refinery Flare (FL-7202) Zone E Coker Flare (FL-7201) 	Flare, Billings/ Laurel SO ₂ Stipulation
EU018	RCRA Units	Restrictions on Land Tillage (HSPA permit)
EU019	Cooling Towers <ul style="list-style-type: none"> Cooling Towers #1 - #3 Cooling Tower #5 Cooling Tower #6 	None
EU020	Saturate Gas Concentration Unit – <i>Eliminate EU, naphtha splitter consolidated with EU002</i>	

EU021	Ultra Low Sulfur Diesel (ULSD) (900 Unit) and Hydrogen Plant (1000 Unit) <ul style="list-style-type: none"> • Reactor Charge Heater (H-901) • Fractionator Reboiler (H-902) • Reformer Heater (H-1001) 	LDAR
EU022	Delayed Coker Unit <ul style="list-style-type: none"> • Coker Charge Heater (H-7501) • Coke Processing Operations 	LDAR, reasonable precautions for coke processing
EU023	Zone E SRU and TGTU	LDAR

C. Categorically Insignificant Sources/Activities

Appendix A of Operating Permit #OP1821-05 lists insignificant emission units at the facility. The permittee is not required to update a list of insignificant emission units; therefore, the emission units and/or activities may change from those specified in Appendix A.

SECTION III. PERMIT CONDITIONS

A. Emission Limits and Standards

Emission limits and standards in the Title V permit were established from preconstruction permits, the Billings/Laurel SIP, NSPS requirements, NESHAP requirements, MACT requirements, and the USEPA Consent Decree entered February 2004. CHS currently has 27 active preconstruction permits. The following is a list of those permit numbers: #9-091868, #56-091569, #55-091569, #105-042970, #129-062270, #272-061171, #363-112971, #364-112971, #362-112971, #499-102372, #540-030773, #664-112073, #665-112073, #674-121973, #800-041675, #1111, #1161, #1176, #1175, #1168, #1169, #1170, #1173, #1174, #1317, #1552, #1821-19. Permits #14-110768, #1171, and #1172 were revoked.

B. Monitoring Requirements

ARM 17.8.1212(1) requires that all monitoring and analysis procedures or test methods, required under applicable requirements, be contained in operating permits. In addition, when the applicable requirement does not require periodic testing or monitoring, periodic monitoring must be prescribed that is sufficient to yield reliable data from the relevant time period that is representative of the source's compliance with the permit.

The requirements for testing, monitoring, recordkeeping, reporting, and compliance certification sufficient to assure compliance, does not require the permit to impose the same level of rigor for all emission units. Furthermore, it does not require extensive testing or monitoring to assure compliance with the applicable requirements for emission units that do not have significant potential to violate emission limitations or other requirements under normal operating conditions. When compliance with the underlying applicable requirement for an insignificant emission unit is not threatened by lack of regular monitoring and when periodic testing or monitoring is not otherwise required by the applicable requirement, the status quo (**i.e., no monitoring**) will meet the requirements of ARM 17.8.1212(1). Therefore, the permit does not include monitoring for insignificant emission units.

The permit includes periodic monitoring or recordkeeping for each applicable requirement. The information obtained from the monitoring and recordkeeping will be used by the permittee to periodically certify compliance with the emission limits and standards. However, the Department may request additional testing to determine compliance with the emission limits and standards.

C. Test Methods and Procedures

The operating permit may not require testing for all sources if routine monitoring is used to determine compliance, but the Department has the authority to require testing if deemed necessary to determine compliance with an emission limit or standard. In addition, the permittee may elect to voluntarily conduct compliance testing to confirm its compliance status.

D. Recordkeeping Requirements

The permittee is required to keep all records listed in the operating permit as a permanent business record for at least 5 years following the date of generation of the record.

E. Reporting Requirements

Reporting requirements are included in the permit for each emission unit, and Section V of the operating permit, "General Conditions", explains the reporting requirements. However, the permittee is required to submit quarterly reports, semi-annual monitoring and annual monitoring reports to the Department and to annually certify compliance with the applicable requirements contained in the permit. The reports must include a list of all emission limit and monitoring deviations, the reason for any deviation, and the corrective action taken as a result of any deviation.

To eliminate redundant reporting, a source may reference previously submitted reports (with at least the date and subject of the report) in the semi-annual and annual reports instead of resubmitting the information in quarterly, and/or other reports. However, a source must still certify continuous or intermittent compliance with each applicable requirement annually.

F. Public Notice

In accordance with ARM 17.8.1232, a public notice was published in the *Billings Gazette* newspaper on or before September 14, 2010. The Department provided a 30-day public comment period on the draft operating permit from September 14, 2010, to October 14, 2010. ARM 17.8.1232 requires the Department to keep a record of both comments and issues raised during the public participation process. The comments and issues received are summarized below, along with the Department's responses.

Summary of Public Comments

Person/Group Commenting	Comment	Department Response
	No public comments were received.	

G. Draft Permit Comments

Summary of Permittee Comments

Permit Reference	Permittee Comment	Department Response
Section II: Summary of Emission Units Table	As updated in Section III.H, the description of EU007 should be changed to "Platformer Unit, including the Benzene Reduction Unit." Additionally, the emission source "Benzene Reduction Unit Oily Water Sewer" listed as part of EU016 should be moved to EU007.	Operating Permit changed as requested.
EU005 Summary Table	The "Compliance Frequency" cells for the NOx and CO limits for the NHT Charge Heater should be updated to "Every Two Years" to match the compliance demonstration requirement of F.14.	Operating Permit changed as requested.
I.45.d.	For consistency with the MAQP, this reporting requirement should be removed from the operating permit.	This reporting requirement is included in MAQP #1821-22 under Section X.H: "Emission reporting for CO from the emission monitor shall consist of a daily maximum 1-hour average (ppm) for each calendar day." No changes were made to the Operating Permit.
EU010 Summary Table	The "Compliance Frequency" cells for the NOx and CO limits for H-202 and H-201 should be updated to "Every Two Years" to match the compliance demonstration requirements of K.30 and K.31.	Operating Permit changed as requested.
EU013 Summary Table	The "Compliance Frequency" cells for the NOx and CO limits for Boiler 10 (following ULNB installation) should be updated to "Every 5 Years" to match the compliance demonstration requirement of N.33.	Operating Permit changed as requested.
P.3.	This requirement should be clarified as follows: "CHS shall commence construction on the <i>expansion of the</i> Railcar Light Product Loading Rack no later than June 27, 2011 (three years following issuance of MAQP #1821-17) <i>or the construction permit for</i>	Operating Permit changed as requested.

	<i>such expansion shall expire.”</i>	
P.19.	The Railcar Light Product Loading Rack VCU has been installed and initial testing has been completed. CHS received approval as part of MAQP #1821-17 to construct an expansion of the loading facilities. As such, this requirement should be clarified as follows: “The VCU shall be initially tested for VOC’s, and compliance monitored with the emission limitations contained in Section III.P.5 within 180 days of initial startup and testing continued every 5 years, or according to another testing/monitoring schedule as may be approved by the Department, until such time that the <i>expansion of the Railcar Light Product Loading Rack</i> is complete. Following construction completion of the Railcar Light Product Loading Rack <i>expansion</i> , the VCU shall be tested on an every 2-year basis. CHS shall perform the test methods and procedures as specified in 40 CFR 63.425, Subpart R.”	Operating Permit changed as requested.
EU010 Summary Table	The “Compliance Frequency” cells for the NOx and CO limits for H-901 and H-902 should be updated to “Every Two Years” to match the compliance demonstration requirements of V.26 and V.27.	Operating Permit changed as requested.

Summary of EPA Comments

Permit Reference	EPA Comment	Department Response
	No EPA Comments were received.	

SECTION IV. REQUIREMENTS NOT IDENTIFIED AS NON-APPLICABLE

Pursuant to ARM 17.8.1221, CHS requested a permit shield for all non-applicable regulatory requirements and regulatory orders identified in the tables in Section 8 of the permit application. In addition, the CHS permit application also requested a permit shield for both the facility and for certain emission units. The Department has determined that the requirements identified in the permit application for the individual emission units are non-applicable. These requirements are contained in the permit in Section IV - Non-applicable Requirements.

The following table outlines those requirements that CHS had identified as non-applicable in the permit renewal application, but will not be included in the operating permit as non-applicable. The table includes both the applicable requirement and reason that the Department did not identify this requirement as non-applicable.

Applicable Requirement	Reason for Not Including
40 CFR 63, Subpart ZZZZ Consent Decree CV-03-153-BLG-RFC (entered 2/23/04)	This rule has become applicable since the submittal of the renewal application. The Consent Decree is required to be included in the Title V Operating Permit under ARM 17.8.1211.

SECTION V. FUTURE PERMIT CONSIDERATIONS

A. MACT Standards

CHS is currently subject to 40 CFR 63, Subparts R, CC, UUU, and ZZZZ. This facility would also be subject to 40 CFR 63, Subpart DDDDD –NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters (also referred to as the Boiler MACT). However, on July 30, 2007, the Court of Appeals for the District of Columbia Circuit issued its mandate in NRDC v. EPA, vacating and remanding EPA's Boiler MACT. This rule was subsequently removed from the ARM in October 2008 and, as such, does not apply to this facility at this time.

The Department is not aware of any proposed or pending MACT standards, in addition to those already listed, that may be applicable.

B. NESHAP Standards

The Department is not aware of any proposed or pending NESHAP standards, in addition to those already listed, that may be applicable.

C. NSPS Standards

The Department is not aware of any proposed or pending NSPS standards, in addition to those already listed, that may be applicable at this time. However, CHS will be subject to any applicable changes to 40 CFR 60, Subpart VV (proposed November 7, 2006).

D. Risk Management Plan

This facility does exceed minimum threshold quantities for any regulated substance listed in 40 CFR 68.115 for any facility process. Consequently, this facility is required to submit a Risk Management Plan.

If a facility has more than a threshold quantity of a regulated substance in a process, the facility must comply with 40 CFR 68 requirements no later than June 21, 1999; 3 years after the date on which a regulated substance is first listed under 40 CFR 68.130; or the date on which a regulated substance is first present in more than a threshold quantity in a process, whichever is later.

E. Compliance Assurance Monitoring (CAM) Plan

An emitting unit located at a Title V facility that meets the following criteria listed in ARM 17.8.1503 is subject to Subchapter 15 and must develop a CAM Plan for that unit:

- The emitting unit is subject to an emission limitation or standard for the applicable regulated air pollutant (other than emission limits or standards proposed after November 15, 1990, since these regulations contain specific monitoring requirements);
- The emitting unit uses a control device to achieve compliance with such limit; and
- The emitting unit has potential pre-control device emission of the applicable regulated air pollutant that are greater than major source thresholds/

CHS does not currently have any emitting units that meet all the applicability criteria in ARM 17.8.1503, and is therefore not currently required to develop a CAM Plan.