MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY
OPERATING PERMIT TECHNICAL REVIEW DOCUMENT

Air, Energy & Mining Division
1520 E. Sixth Avenue
P.O. Box 200901
Helena, Montana 59620-0901

Phillips 66 Pipeline LLC
Billings Pipeline and Terminal Operations
NW¼ Section 2, Township 1 South, Range 26 East, Yellowstone County
2626 Lillian Avenue
Billings, MT 59101

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		
Ambient Monitoring Required		X	
COMS Required		X	
CEMS Required		X	
Continuous Parameter Monitoring	X		VCU - Thermocouple
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 Permit (MAQP)	X		MAQP #2619-44 (part of the Refinery MAQP)
New Source Performance Standards (NSPS)	X		40 CFR 60, Subpart A, Subpart VV, Subpart XX, Subpart GGG
National Emission Standards for Hazardous Air Pollutants (NESHAPS)	X		40 CFR 61, Subpart M
Maximum Achievable Control Technology (MACT)	X		40 CFR 63, Subpart R, Subpart CC, Subpart EEE
Major New Source Review (NSR), including 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 SIP

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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 United States 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 by Conoco Inc. (Conoco) on June 12, 1996; subsequent settlement stipulation and order of dismissal of Conoco's Title V permit appeal, filed on July 9, 2002; two administrative amendments received December 19, 2002, and October 10, 2003, filed by ConocoPhillips Company; the renewal application submitted January 10, 2007; a de minimis request dated January 31, 2008; Administrative Amendment requests received from ConocoPhillips on June 10, 2009, July 9, 2009, September 2, 2009, and September 15, 2009; Administrative Amendment requests received on March 19, 2012 and May 1, 2012; Title V renewal application received on December 19, 2012; an Administrative Amendment request received on September 4, 2015, the Title V renewal application received on February 22, 2018, and the administrative amendment request received on December 14, 2022.

B. Facility Location

The Phillips 66 Pipeline LLC - Billings Pipeline and Terminal Operations (Phillips 66 Pipeline) is located in the NW¼, Section 2, Township 1 South, Range 26 East, Yellowstone County. This legal description refers to the physical address of 401 South 23rd Street, Billings, Montana.

The facility is considered a support facility for Phillips 66 Company – Billings Refinery, which operates under the Title V Operating Permit #OP2619. As such, it is included in conjunction with the refinery during Prevention of Significant Deterioration (PSD), Maximum Achievable Control Technology (MACT), and other permitting determinations. The two facilities are currently both contained in Montana Air Quality Permit (MAQP) #2619-44. The transportation operations were previously permitted as part of the refinery's Title V Operating Permit #OP2619-01. However, since there are separate management structures, the facility requested to separate the transportation operations from the refinery in the operating permit.

C. Facility Background Information

Montana Air Quality Permit (MAQP) Background

ConocoPhillips has received several air quality permits throughout the past years for various pieces of equipment and operations. All previously permitted equipment, limitations, conditions, and reporting requirements stated in **MAQPs #1719, #2565, #2669, #2619**, and **#2619A** were included in **MAQP #2619-02**. Numerous permit modifications affecting the Billings Refinery, including the Pipeline Product Terminal, were made to MAQP #2619-02, and are on file with the Department of Environmental Quality – Air Quality Bureau (Department). Specific permit modifications affecting the Terminal are summarized as follows.

MAQP #2619-10: On July 30, 1997, MAQP #2619-10 was issued to Conoco in order to comply with 40 CFR 63, Subpart R- National Emission Standards for Gasoline Distribution Facilities. Conoco proposed to install a gasoline vapor collection system and enclosed firebox within the vapor combustion unit (VCU) for the reduction of Hazardous Air Pollutants (HAPs) resulting from the loading of gasoline. The VCU was added to the bulk gasoline and distillate loading rack. The gasoline vapors are collected from the trucks during loading and then routed to an enclosed firebox within the VCU where combustion occurs. This project resulted in an overall reduction in the amount of actual emissions of volatile organic compounds (VOCs) of 94.8 tons per year (tpy). The reduction in potential emissions of VOCs is 899.5 tpy, while carbon monoxide (CO) increases to 19.7 tpy and oxides of nitrogen (NO_x) increases to 7.9 TPY emissions.

Conoco also requested an administrative change be made to Section II.F.5, that would bring the permit requirements in alignment with the monitoring requirements specified by 40 CFR 60, Subpart QQQ and 40 CFR 61, Subpart FF.

Because Conoco's bulk gasoline and distillate loading rack VCU is defined as an incinerator under Montana Code Annotated (MCA) 75-2-215, a determination that the emissions from the VCU will constitute a negligible risk to public health was required prior to the issuance of the permit. Conoco and DEQ identified the following hazardous air pollutants from the enclosed firebox within the VCU, which were used in the health risk assessment. These constituents are typical components of gasoline.

1. Benzene
2. Ethyl Benzene
3. Hexane
4. Methyl Tert Butyl Ether
5. Toluene
6. Xylenes

The reference concentrations for Ethyl Benzene, Hexane, and Methyl Tert Butyl Ether were obtained from EPA's IRIS database. The risk information, for the remaining hazardous air pollutants, is contained in the January 1992 CAPCOA Risk Assessment Guidelines. The model performed by Conoco for the hazardous air pollutants, identified above, monitored compliance with the negligible risk requirement.

MAQP #2619-11: On December 10, 1997, Conoco requested a modification to MAQP #2619-10. In addition to changes to the Refinery, Conoco also requested to be consistent with the wording as specified by 40 CFR 63, Subpart R. DEQ replaced all references to "tank trucks" with "cargo tank" and all references to "truck-loading rack" with "loading rack" and made other administrative changes. MAQP #2619-11 was issued to Conoco.

MAQP #2619-24: On November 19, 2008, MAQP #2619-24 was issued to ConocoPhillips. MAQP #2619-24 included clarification language for the emissions control requirements associated with the bulk loading gasoline and distillates loading rack operation and maintenance.

MAQP #2619-28: On May 3, 2012, DEQ of Environmental Quality (Department) received a request to administratively amend MAQP #2619-28 to incorporate a change in the ConocoPhillips Company name. On May 1, 2012, the downstream portions of the ConocoPhillips Company were spun-off as a separate company named Phillips 66 Company

(Phillips 66). Because of the spin-off, the former ConocoPhillips Billings Refinery is now the Phillips 66 Billings Refinery. The permit action incorporated the name change throughout. MAQP #2619-29 replaced MAQP #2619-28.

On October 9, 2012, DEQ received an Administrative Amendment Request to delete conditions regarding the New Crude and Vacuum Unit because the project was cancelled, clarification of various rule applicabilities and other minor edits. A letter outlining the requested changes in bullet point fashion is on file with DEQ. **MAQP #2619-30** replaced MAQP #2619-29.

On May 1, 2014, DEQ received an Administrative Amendment request from Phillips 66. Phillips 66 is in the process of taking steps to close out the Consent Decree with the Environmental Protection Agency (EPA) and the State of Montana. Phillips 66 requested that limits and standards from the Consent Decree which are required to live on beyond the life of the Consent Decree be present in the permit, with authority for those conditions to rest outside of regulatory reference to the Consent Decree itself. The action removed references to the Consent Decree as a regulatory basis. The changes taking place in this action are tabelized below. Following the first table is a table which contains additional information regarding all conditions in the MAQP which are believed to have originated through the Consent Decree. **MAQP #2619-31** replaced MAQP #2619-30.

MAQP #2619-31 Table 1: Changes taking place in this action

MAQP #2619-30 Condition	Source	Pollutant	Obligation	CD Paragraph	Prior Permit Reference	New Regulatory Reference
II.E.5.c.i	Boiler Stack	SO_2	CEMS	71	CD	17.8.749
II.C.1.d.ii	FCC	SO_2	7-day & 365-day limits	40	CD	17.8.749
II.C.1.d.vi	FCC	NOx	7-day & 365-day limits	17	CD	17.8.749
II.C.1.d.iv	FCC	CO	365-day limit	50	CD	17.8.749
II.C.1.d.v	FCC	CO	1-hr limit	49	CD	17.8.749
II.C.1.d.vii	FCC	PM	1 lb/1000 lb coke burn	46, 47(a)	CD	17.8.749
II.A.1.c.v	FCC	----	NSPS J and A applicability	54	CD	17.8.749
II.C.1.d.iii	FCC	SO_2	NSPS J limit	54	CD	17.8.749
II.C.1.d.vii	FCC	PM	NSPS J limit	54	CD	17.8.749
II.C.1.d.viii	FCC	Opacity	NSPS J limit	54	CD	17.8.749
II.E.5.b.v	FCC	NOx	CEMS	28	CD	17.8.749
II.E.5.b.iv	FCC	CO	CEMS	49	CD	17.8.749
II.E.5.b.vi	FCC	O_2	CEMS	28, 37	CD	17.8.749
II.E.5.b.i	FCC	SO_2	CEMS	37	CD	17.8.749
II.E.5.b.iii	FCC	Opacity	COMS	47(b)	CD	17.8.749
II.E.4	FCC	PM	Particulate Emissions Test-annual	47(a)	CD	17.8.749
II.B.1	Flare-Refinery	SO_2	RCFAs & FGRS	162	CD	17.8.749
II.A.1.c.iii	Flare-Refinery	SO_2	NSPS J and A applicability	161	CD	17.8.749

MAQP #2619-30 Condition	Source	Pollutant	Obligation	CD Paragraph	Prior Permit Reference	New Regulatory Reference
II.A.1.c.iv	Flare-Jupiter	SO_2	NSPS J and A applicability	155	CD	17.8.749
II.A.1.c.i	Heaters/Boilers	SO_2	NSPS J applicability	69	none	17.8.749
II.C.1.e.i	Heaters	SO_2	No fuel oil burning	**	none	17.8.749
II.C.1.e.iii	Heaters	SO_2	Limit of 0.10 gr/dscf H_2S in fuel gas	69	none	17.8.749
II.C.1.f.iv	Boilers	SO_2	Limit of 0.10 gr/dscf H_2S in fuel gas	69	none	17.8.749
II.C.1.f.ii	Boilers	SO_2	300 ton/365-day rolling avg.***	71	CD	17.8.749
absent	Flare-Jupiter	SO_2	RCFAs for NSPS J	179	none	17.8.749

*** Condition existed in MAQP prior to Consent Decree
** Not in Consent Decree but requested as part of this action

MAQP #2619-31 Table 2: All conditions originating from Consent Decree

Source	CD Limit or Obligation	MAQP #2619-30 Permit Condition	Compliance Demonstration
FCCU	365-Day Rolling Average NO_x Emission =49.2 ppmvd @ 0% O_2 7-Day Rolling Average NOx Emission = 69.5 ppmvd @ 0% O_2 Hydrotreater Outages (7-Day Limit Shall Not Apply)	Sec. II.C.1.d.vi	Sec. II.E.5.b.v Sec. II.E.b.vi Sec. II.E.7 Sec. II.E.8
FCCU	365-Day Rolling Average SO_2 Emission = 25 ppmvd @ 0% O_2 7-Day Rolling Average SO_2 Emission = 50 ppmvd @ 0% O_2 Hydrotreater Outages (7-Day Limit Shall Not Apply)	Sec. II.C.1.d.ii	Sec. II.E.5.b.i Sec. II.E.b.vi Sec. II.E.7
FCCU	PM Emission = 1 lb/1000 lbs coke burned	Sec. II.C.1.d.vii	Sec. II.E.4
FCCU	1-Hour Average CO Emission = 500 ppmvd @ 0% O_2 (Startup, Shutdown, or Malfunctions not used in determining compliance with this limit. - 2nd Amendment) 365-Day Rolling Average CO Emission = 150 ppmvd @ 0% O_2	Sec. II.C.1.d.v Sec. II.C.1.d.iv	Sec.II.E.5.b.iv Sec. II.E.7
FCCU	Must comply with NSPS Subpart A and J - SO_2	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec. II.C.1.d.iii *(Emission Limit)*	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec.II.E.5.b.i *(Emission Monitoring)* Sec. II.E.7 *(Emission Monitoring)*
FCCU	Must comply with NSPS Subpart A and J - PM	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec. II.C.1.d.vii *(CD Emission Limit)*	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec.II.E.4 *(Emission Testing)*

Source	CD Limit or Obligation	MAQP #2619-30 Permit Condition	Compliance Demonstration
FCCU	Must comply with NSPS Subpart A and J - CO	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec. II.C.1.d.v *(CD Emission Limit)*	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec.II.E.5.b.iv *(Emission Monitoring)* Sec. II.E.7 *(Emission Monitoring)*
FCCU	Must comply with NSPS Subpart A and J - Opacity	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec. II.C.1.d.viii *(Emission Limit)*	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.v *(General Condition)* Sec.II.E.5.b.iii *(Emission Monitoring)* Sec. II.E.7 *(Emission Monitoring)*
Boilers	Must comply with NSPS Subpart J (SO_2, CO & PM) 365-Day Rolling Average SO_2 Emissions = 300 tpy (Fuel-Oil Burning Only)	Sec. II.A.1.c.i *(General Condition)* Sec. II.C.1.f.ii *(Emmission Limit)* Sec. II.C.1.f.iii *(Emission Limit)*	Sec. II.A.1.c.i *(General Condition)* Sec. II.E.5.c.i *(Emission Monitoring)* Sec. II.E.7 *(Emission Monitoring)* Sec. II.E.5.e *(Emission Monitoring)*
Heaters	Must comply with NSPS Subpart J (SO_2, CO & PM) 365-Day Rolling Average SO_2 Emissions = 300 tpy (Fuel-Oil Burning Only)	Sec. II.A.1.c.i *(General Condition)* Sec. II.C.1.e.i *(Operating Condition)* Sec. II.C.1.f.iii *(Emission Limit)*	Sec. II.E.5.e *(Emission Monitoring)*
SRU/Ammonium Sulfide Unit Flare (Jupiter Flare)	Must comply with NSPS Subpart A and J.	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.iv *(General Condition)* Sec. II.C.7 *(Operating Condition)*	Sec. II.E.5.f
Main Plant Flare (Refinery)	Must comply with NSPS Subpart A and J.	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.iii *(General Condition)* Sec. II.B.1 *(Control*	Sec. II.E.5.f

Source	CD Limit or Obligation	MAQP #2619-30 Permit Condition	Compliance Demonstration
		Requirement) Sec. II.C.6.a *(Operating Condition)*	
Jupiter SRU/ATS Main Stack	Must comply with NSPS Subpart A and J.	Sec. II.A.1.a *(General Condition)* Sec. II.A.1.c.ii *(General Condition)*	
Main Plant Flare (Refinery)	Root Cause Failure Analysis	Sec. II.C.6	

On September 16, 2014, DEQ received an application from Phillips 66 to propose physical and operational changes to process units and auxiliary facilities at the refinery in order to provide more optimized operations for a broader spectrum of crude oil slates. This application was assigned **MAQP #2619-32**. Changes were primarily related to certain crude distillation, hydrogen production and recovery, fuel gas amine treatment, wastewater treatment, and sulfur recovery equipment and operations. A detailed list of project-affected equipment with a description of the changes proposed is presented below:

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
Small Crude Unit Heater, H-1	Existing	55.92 MMBtu/hr (HHV)	The tubes in the Small Crude Unit Heater, H-1 will be replaced with upgraded metallurgy tubes. Phillips 66 has not sought to treat this change as qualifying for one of the exemptions from what is a physical change or change in the method of operation under relevant PSD regulations.
Vacuum Furnace, H-17 – Existing Furnace	Existing	n/a	This emissions unit will be discontinued from service and replaced by a new process heater, as noted below.
Vacuum Furnace, H-17 – Replacement Furnace	New	75 MMBtu/hr (HHV)	This emissions unit will be constructed to replace the refinery's existing Vacuum Furnace, H-17, which, as noted above, will be removed from service.

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
FCCU Preheater, H-18	Existing	77 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project because the actual feed rate (and the gas oil content of the feedstock) to the No. 4 HDS Unit, which provides the feed to this heater, is anticipated to increase due to the project. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
Large Crude Unit Heater, H-24	Existing	108.36 MMBtu/hr (HHV)	This emissions unit will be physically modified, including the installation of upgraded metallurgy tubes to replace the existing tubes in the heater and the installation of ULNBs to replace the existing burners in the heater.
FCCU Stack	Existing	8,285.50 million barrels per year (gas oil feed)	Phillips 66 estimated that the project would result in an increase in the actual FCCU catalyst regenerator coke burn rate equal to approximately 12% of its annual average potential to emit coke burn rate. This coke burn rate increase will be associated with the actual increase in throughput and slightly heavier gas oil feedstock expected for the FCCU. The increase in throughput and gas oil feedstock density for the FCCU will occur because the No. 4 HDS Unit, which provides the feed to the FCCU, is estimated to experience an increase in the gas oil content of its feed, as well as an overall increase in its actual feed rate, as a result of the project. These changes to the No. 4 HDS Unit feed will occur because of the improved separation capabilities of the new Vacuum Unit Fractionator (W-57). The estimated increase in actual FCCU catalyst regenerator coke burn rate will make use of existing coke burn rate capacity that is not currently being utilized. The project does not propose to increase the coke burn rate capacity or the potential to emit emission rates of the FCCU catalyst regenerator.
Storage Tanks	Existing		Certain storage tanks at the refinery are anticipated to experience an increase in actual annual throughput primarily because of the improved straight run diesel and gas oil separation operations that will occur as a result of the project. This improvement in straight run diesel and gas oil separation will generally result in an increase in the throughput for diesel and gas oil storage tanks at the refinery. On the other hand, certain storage tanks at the refinery will experience a decrease in actual annual throughput as a result of the project. The refinery storage tanks expected to experience a decrease in throughput are those tanks that generally store lighter (higher vapor pressure) materials, such as gasoline and gasoline blendstocks. These actual throughput decreases have not been evaluated for PSD applicability determination purposes (*i.e.*, any emissions decreases that may result due to these throughput decreases have not been estimated because Phillips 66 does not intend to make such emissions decreases creditable). Additionally, the Desalter Break Tanks (T-4510 and T-4511) at the refinery will be removed from service and replaced by two new API separator bays (including associated equipment).

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
Fugitive VOC Emissions	Existing-New		New piping fugitive components (*e.g.*, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, and flanges or other connectors) are expected to be added to the refinery as a result of the project due to certain piping and equipment additions that will occur as part of the project. Also, new process drains and junction boxes are anticipated to be added to the refinery as part of the project. Furthermore, the Primary OWS (T-163) at the refinery will be removed from service and replaced by two new API separator bays (including associated equipment).
CPI Separator Tanks	Existing		The OWSs (CPI OWSs (T-169 and T-170)) representing this emissions unit are planned to be removed from service and replaced by two new API separator bays (including associated equipment).
No. 4 HDS Recycle Hydrogen Heater, H-8401	Existing	31.20 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in an increase in the actual feed rate to the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
No. 4 HDS Fractionator Feed Heater, H-8402	Existing	31.70 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in an increase in the actual feed rate to the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
No. 1 H_2 Unit Reformer Heater, H-9401	Existing	179.20 MMBtu/hr PSA Gas, HHV 76.80 MMBtu/hr Natural Gas/Cryo Gas, HHV	Modifications will be made to the burners in the No. 1 H_2 Unit Reformer Heater, H-9401 (EPN 35) to improve the flame pattern of these burners and to reduce hot spots on the tubes located in this heater. The type of burner modification may include changing the angle of the burners relative to this heater's tubes. Phillips 66 has not sought to treat this change as qualifying for one of the exemptions from what is a physical change or change in the method of operation under relevant PSD regulations.
Coke Handling	Existing		Based on engineering calculations, the actual annual coke production rate of the Coker Unit is expected to increase as a result of the project due to the heavier vacuum residuum that will be sent to the Coker Unit after the implementation of the project. Therefore, the actual annual amount of coke handled at the refinery is expected to increase as a result of the project.

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
No. 5 HDS Charge Heater, H-9501	Existing	25.0 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project primarily because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in more diesel range material being routed to the No. 5 HDS Unit rather than the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
No. 5 HDS Stabilizer Reboiler Heater, H-9502	Existing	49.00 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project primarily because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in more diesel range material being routed to the No. 5 HDS Unit rather than the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
No. 2 H_2 Unit Reformer Heater, H-9701	Existing	111.35 MMBtu/hr PSA Gas, HHV 79.65 MMBtu/hr Natural Gas/Cryo Gas, HHV	The actual feed rate to this process heater is anticipated to increase as a result of the project in order to provide a portion of the increase in hydrogen production expected to be required by the project. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 15% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
Coker Vent and Coke Cutting	Existing		Based on engineering calculations, the actual annual coke production rate of the Coker Unit is expected to increase as a result of the project due to the heavier vacuum residuum that will be sent to the Coker Unit after the implementation of the project. In association with this annual coke production rate increase is a decrease in coke drum cycle time. Therefore, the actual annual number of coke drum opening and coke cutting events is expected to increase as a result of the project.
Cooling Tower	New	7,000 gallons per minute	This cooling tower will be newly constructed to accommodate the increase in cooling water demand estimated to be required by the modified Vacuum Unit.
Railcar Clarified Oil Loading	Existing		The existing railcar clarified oil loading operation at the refinery is anticipated to experience an increase in annual throughput relative to the current annual throughput at which this operation typically operates due to the higher annual operating rate expected for the FCCU as a result of the project.

Summary of Project-Impacted Emissions Units			
Emissions Unit	**Type of Unit (Existing/New)**	**Maximum Capacity**	**Project Impact**
API Separator Tanks	New	132,058 thousand gallons per year	The OWSs representing this emissions unit will replace the following equipment currently located at the refinery: (1) Desalter Break Tanks (T-4510 and T-4511); (2) Primary OWS (T-163); and (3) CPI OWSs (T-169 and T-170). The Oil Water Separator system includes the separator tanks themselves and associated equipment. See 40 CFR §63.1041 definition of Separator. The oil water separator system includes the slop oil vessel (T-4526) and Sludge Hopper (T-4527).
Jupiter Main Stack No. 1	Existing		SRU No. 1, which emits through this stack, will experience multiple physical changes to accommodate a portion of the increased amount of sulfur-containing compounds that will be routed to the Jupiter Plant as a result of the project.
Jupiter Main Stack No. 2	New		SRU No. 3, which will emit through this stack, will be newly constructed as part of the project to accommodate a portion of the increased amount of sulfur-containing compounds that will be routed to the Jupiter Plant as a result of the project.
Jupiter Cooling Tower, CT-615A/B/C	New	7,500 gallons per minute	This cooling tower will be newly constructed to accommodate the increase in cooling water demand estimated to be required by the Jupiter Plant as a result of the project.
Jupiter Cooling Tower CT-120	New	11,500 gallons per minute	This cooling tower will replace the existing cooling tower located at the Jupiter Plant. This Cooling Tower was approved via de minimis after initial permitting of the Vacuum Improvement Project. As required by the de minimis provisions of ARM 17.8.745, review occurred to ensure the emissions from the cooling tower would not have triggered need for PSD permitting for the Vacuum Improvement Project.
Jupiter Sulfur Storage Tanks	Existing-New		The two existing atmospheric sulfur storage tanks (V-117 and V-355) at the refinery may experience an increase in actual annual throughput due to improved sulfur recovery operations of the respective SRUs associated with these tanks and an increase in sulfur loading to the same respective SRUs. Additionally, a new atmospheric sulfur storage tank (V-370) is proposed to be installed at the refinery as part of the project.
Jupiter Railcar and Tank Truck Sulfur Loading	Existing-New		The existing railcar and tank truck sulfur loading arms at the refinery may experience an increase in actual annual throughput as a result of the project. Additionally, one new railcar sulfur loading arm and one new tank truck sulfur loading arm are planned to be installed at the refinery as part of the project.

On September 21, 2015, DEQ received an administrative amendment request from Phillips 66 to clarify certain provisions and emission limits that were initially adopted under the consent decree. The revisions also address the triggering of 40 CFR 60 Subpart Ja for certain units, including flares. Per 40 CFR 60 Subpart Ja, flares which have triggered Subpart Ja and were meeting Subpart J requirements pursuant to a federal consent decree, will continue to meet those requirements until November 11, 2015, at which time all the requirements of Subpart Ja will apply. The requested permit changes included clarification of how the modified flares will comply before and after November 11, 2015.

MAQP #2619-33 replaced MAQP #2619-32.

On March 14, 2016, DEQ received from Phillips 66 a request for an administrative amendment of the MAQP. Changes requested include updating information regarding the cooling towers to be installed as part of the Vacuum Improvement Project to reflect changes made and approved through the de minimis provisions of ARM 17.8.745, and to correct an error regarding identification of tanks which will be removed from service as part of the Vacuum Improvement Project. Lastly, the letter received on March 14th provided notice regarding a change in stack height for the Large Crude Unit Heater H-24, from 152 feet to 195 feet 10 inches. No revision to the MAQP was necessary for the stack height change and a separate de minimis approval letter was sent to Phillips 66 regarding this change. **MAQP #2619-34** replaced MAQP #2619-33.

On April 24, 2017, DEQ received from Phillips 66 a request for an administrative amendment of the MAQP to clarify equipment associated with the API Separator System being installed as part of the Vacuum Improvement Project. Specifically, this permit update clarifies that the API Separator System includes the "Slop Oil Vessel T-4526" and the "Sludge Hopper T-4527". P66 has requested this clarification to ensure that equipment installed on-site is understood to have been included at the time of permitting of the Vacuum Improvement Project. DEQ agreed and noted that the Separator System consists of equipment which includes the aforementioned units, and in fact, the definition of a Separator in relevent federal rules includes not only the separation unit itself but also the forebay and other separator basins and sludge hoppers, amongst other equipment (see 40 Code of Federal Regulations (CFR) §63.1041). Section II.J.7 of the MAQP was updated to reflect the separator system.

The permit was also updated to reflect the de minimis addition of a residuum tank, identified as Tank # T-0852, to condition II.A.3.c. This tank will hold crude distillation residuum and will allow the existing Tank 107 to be temporarily taken out of service for inspections. **MAQP #2619-35** replaced MAQP #2619-34.

On March 29, 2018, DEQ received from Phillips 66 an application to modify the oxides of nitrogen (NO_X) emissions limitations associated with the No. 1 H_2 Plant Reformer Heater, H-9401. Based on source testing, the 0.030 pound per million british thermal units (lb/MMBtu) NO_X emissions limit was found not achievable. Because this heater was modified as part of the Vacuum Improvement Project, the current action entails a Prevention of Significant Deterioration (PSD) lookback to this project. The analysis as completed at that time is essentially re-worked utilizing the higher NO_X emissions factor now applied to the heater. The netting analysis is included in the permit analysis, and the increases do not change the status of the Vacuum Improvement Project as not triggering PSD for NO_X.

Additional information was received on April 23rd regarding the limit and determination of applicable federal rules. On April 24, 2018, DEQ received an affidavit of publication of public notice, completing the application.

This permit action modified NO_X limits associated with this heater to 0.042 lb/MMBtu. **MAQP #2619-36** replaced MAQP #2619-35.

On December 20, 2018, DEQ received from P66 an application to modify the MAQP and Title V to add two backup engines to the facility, a 665 horsepower (hp) portable backup fire pump and a 300 hp emergency backup engine for redundant HDS Flare Drum Pumps. A limit of operation of 1,000 hours is proposed for the Flare Drum Pump engine. Both engines are to be Tier III rated. At the request of P66, the permit action incorporated these engines and corresponding limitations. **MAQP #2619-37** replaced MAQP #2619-36.

On January 10, 2020, DEQ received from Phillips 66 Company an application to change particulate matter emissions limitations associated with the Sulfur Recovery Operations. Following construction and commencement of operation of modifications made in support of and permitted as part of the Vacuum Improvement Project in MAQP #2619-32, the emissions of particulate matter as measured by Environmental Protection Agency (EPA) Methods 201a and 202 were found to be in excess of that allowed by permit conditions.

Following extensive review by Phillips 66 and Jupiter Sulphur, LLC to minimize emissions including condensable emissions, based on additional source testing, the limitations were determined unachievable. The current action increases the allowable emissions from Main Stack 1 and 2 to levels proposed as achievable by Phillips 66. Because these limits were established as part of the Vacuum Improvement Project, and the limits served in part to define allowable emissions which ensured the project did not exceed thresholds triggering the Prevention of Significant Deterioration (PSD) requirements of ARM 17.8 Subchapter 8, the current action is reviewed as if re-permitting the action of MAQP #2619-32. In doing so, the project triggers PSD for particulate matter, particulate matter with aerodynamic diameter of 10 microns or less, and particulate matter with aerodynamic diameter of 2.5 microns or less. The project also triggers PSD for greenhouse gasses. On March 3, 2020, DEQ received modified application information in response to an incompleteness letter.

MAQP #2619-38 increases allowable particulate matter related emissions from Jupiter Main Stacks 1 and 2, and reviews greenhouse gas best available control technology for the physically modified and new emitting units associated with the Vacuum Improvement Project.

On September 23, 2020, DEQ received from Phillips 66 an MAQP application for significant changes to the refinery. The application triggers the Prevention of Significant Deterioration (PSD) program requirements of ARM 17.8 Subchapter 8 for oxides of nitrogen (NO_X), particulate matter with an aerodynamic diameter of 2.5 microns and less ($PM_{2.5}$), particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), and greenhouse gases (GHGs). The project also triggers PSD for ozone based on NO_X.

The refinery is currently designed to refine heavy sour crude oil. In general, this permitting action is a conglomeration of several projects which will ultimately provide Phillips 66 the ability to process crude oils that contain higher percentages of residual material while also maintaining compliance with fuel sulfur content requirements (i.e. – process heavier, sour crude). Physical changes are expected to the crude units, coker unit, fluidized catalytic cracking unit (FCCU), the propylene and butylene mercaptan extracting unit (PB Merox Unit), and the sulfur recovery units (SRUs) at the adjacent Jupiter plant. Additionally, a new hydrogen plant, hydrogen plant #3, will be installed. Changes in operation will also affect emissions from several existing heaters and unit operations including the delayed coking unit.

The permit analysis contains a table detailing all changes proposed to project affected emitting units, as well as a presentation of the net emissions changes, best available control technology (BACT) determinations, and a summary of the ambient air quality impacts including increment consumption.

Relevant permit conditions have been included throughout the permit. In addition, conditions created relevant to the Vacuum Improvement Project, which originally had its own section, have been incorporated into the rest of the permit.

Emissions Unit	**Existing/ New Unit**	**Project Impact**
Catalytic Reforming Unit #2 (H-13) (EPN 64)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 2.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.

Emissions Unit	Existing/ New Unit	Project Impact
Catalytic Reforming Unit #2 (H-14) (EPN 65)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 2.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.
Sat Gas Stabilizer Reboiler (H-16) (EPN 67)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 2.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.
FCCU Preheater (H-18) (EPN 69)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may use all the heater's existing firing rate capacity that is not currently being used. Phillips 66 is not proposing to increase the firing rate capacity of the heater.
Alky Heater (H-21) (EPN 71)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the process heater's annual actual firing rate to increase by an amount equal to approximately 12.5% of its annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.

Emissions Unit	Existing/ New Unit	Project Impact
Catalytic Reforming Unit #2 (H-23) (EPN 72)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 2.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.
Coker Furnace (H-3901) (EPN 74)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may use all the heater's existing firing rate capacity that is not currently being used. Phillips 66 is not proposing to increase the firing rate capacity of the heater.
No. 4 HDS Recycle Hydrogen Heater (H-8401) (EPN 75)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 7.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.
No. 4 HDS Fractionator Feed Heater (H-8402) (EPN 76)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 7.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.

In addition to the above, a new cooling tower will be installed at the Jupiter Sulphur plant. This cooling tower will replace the existing CT-602 cooling tower. The new cooling tower will be of increased capacity. An addendum to the original application was received on October 23, 2020, to request this change be added to the permit application. **MAQP #2619-39** replaced MAQP #2619-38.

On January 6, 2021, DEQ received from Phillips 66 an MAQP application to change the form of limits on the Vacuum Furnace (H-17) and Large Crude Unit Heater (H-24) regarding emissions of oxides of nitrogen (NO_X). Limits on these heaters were originally in the form of a pound per million British thermal unit basis (lb/MMBtu), 30 day rolling average, determined daily, with a daily F-factor determination required. This form of limit requires daily refinery fuel gas analyses, producing a compliance demonstration burden that Phillips 66 preferred to forego. Phillips 66 proposed to revise the form of these emission limitations to an equivalent limit on a parts per million basis. Doing so required that only the concentration of NO_X and oxygen in the stack be measured.

Specifically, Phillips 66 requested that the 0.030 lb/MMBtu limitation on the H-17 heater be changed to a 30 parts per million by volume limitation on a dry basis (ppmvd), at 0% oxygen, on a 30 day rolling average, determined daily. The 0.040 lb/MMBtu limitation on the H-24 was requested to be changed to a 40 ppmvd at 0% oxygen limitation, determined daily on a 30-day rolling average basis. The request resulted in no increase in allowable emissions. A change in emissions monitoring followed, requiring the ppmvd monitoring requirements of 40 Code of Federal Regulations Part 60, Subpart Ja, which is also applicable to these heaters. These limitations are considered equivalent, as demonstrated by 40 CFR 60 Subpart Ja. **MAQP #2619-40** replaced MAQP #2619-39.

On May 4, 2021, DEQ received from Phillips 66 an MAQP application to reinstate flexible limitations on 4 heaters with respect to emissions of oxides of nitrogen (NO_X). It was requested that the Coker Heater H-3901, the No. 4 Hydrodesulfurization Recycle Hydrogen Heater H-8401, the No. 4 Hydrodesulfurization Fractionator Feed Heater H-8402, and the No. 1 Hydrogen Plant Reformer Heater H-9401 be placed under a bubble limit at 17.22 lb/hr and 75.44 tons per year. The request was incorporated as **MAQP #2619-41**, replacing MAQP #2619-40.

On October 29, 2021, DEQ received an application from Phillips 66 to modify the current MAQP. Phillips 66 identified that a physical change at the facility will increase the maximum hourly gas oil throughput rate for the FCCU. The allowable annual average gas oil throughput rate of the FCCU would remain the same; therefore, no change to the allowable annual emissions from the unit would result. However, an increase in the maximum hourly emissions rates may occur. This affects the original ambient air quality analyses for short term particulate matter impacts reviewed in the issuance of MAQP #2619-39. The current action addresses the change in emissions and associated impacts in the ambient impact analyses section of the permit analysis. The DEQ concludes that this update to the project permitted in MAQP #2619-39 would not change the original determination that it would not cause or contribute to an ambient air quality or ambient increment exceedance.

In addition, numerous permit cleanup items including the shutdown or removal of various emitting units are addressed in this action. These changes are tableized below. **MAQP #2619-42** replaced MAQP #2619-41.

Permit Condition	Proposed Permit Condition Revision
• II. Conditions and Limitations.C.7.f • II. Conditions and Limitations.H.1	Phillips 66 proposes to remove the H-2, H-4, H-5, and H-19 heater entries from the referenced permit conditions because the stacks of these idled heaters are being removed from the site, which will make the heaters effectively inoperable.

Permit Condition	Proposed Permit Condition Revision
• II. Conditions and Limitations.C.7.f • II. Conditions and Limitations.H.1	Phillips 66 proposes to remove the H-15 heater entries from the referenced permit conditions because the idled heater is being removed from the site.
• II. Conditions and Limitations.A.3.d • II. Conditions and Limitations.A.3.f • II. Applicable Rules and Regulations.C.10.e	Phillips 66 proposes to remove Proto Gas Tanks #2901 - #2907 from the referenced permit conditions because the tanks are out of service since the knock engines (engines used to measure gasoline and blending component octane ratings) previously fed by the tanks are no longer used. The knock engines have been replaced by analyzers that do not rely on sample materials from the tanks.
• II. Conditions and Limitations.A.1.f • II. Applicable Rules and Regulations.C.8.g	Phillips 66 proposes to remove the T-36 tank entries from the referenced permit conditions because the tank has been removed from the site.
• II. Conditions and Limitations.A.1.f • II. Conditions and Limitations.A.1.g • II. Conditions and Limitations.C.10 • II. Applicable Rules and Regulations.C.8.g • II. Applicable Rules and Regulations.C.8.h	Phillips 66 proposes to remove the T-3201 tank entries from the referenced permit conditions because the tank has been removed from the site.
• II. Conditions and Limitations.A.1.l • II. Applicable Rules and Regulations.C.8.k	Phillips 66 proposes to remove the Corrugated Plate Interceptor (CPI) separators entries from the referenced permit conditions because the CPI separators have been removed from the site. The replacement API separators were installed at the site as authorized by MAQP No. 2619-32, not MAQP No. 1821-32 as currently referenced.
• II. Conditions and Limitations.C.18	Phillips 66 proposes to remove the referenced permit condition because a de minimis notification was submitted to MT DEQ on October 8, 2021, in which Phillips 66 proposed to place the T-4510 and T-4511 tanks back in service.
• II. Conditions and Limitations.C.7.u.i	Phillips 66 proposes to remove the referenced permit condition because it is duplicative of II. Conditions and Limitations.C.7.p.ii.

Permit Condition	Proposed Permit Condition Revision
• II. Conditions and Limitations.C.7.y	Phillips 66 proposes to remove the referenced permit condition because it is duplicative of II. Conditions and Limitations.C.7.p.i. However, be sure to add an ARM 17.8.752 citation to II. Conditions and Limitations.C.7.p.i. when the referenced permit condition is removed.
• II. Conditions and Limitations.C.7.z	Phillips 66 proposes to remove the referenced permit condition and transfer its emission standards to subparagraphs under II. Conditions and Limitations.C.7.p for the No. 1 H_2 Plant Reformer Heater (H-9401) and II. Conditions and Limitations.C.7.t for the No. 2 H_2 Plant Reformer Heater (H-9701), respectively.
• II. Conditions and Limitations.A.1.m • II. Conditions and Limitations.A.3.g • II. Conditions and Limitations.C.20.b • II. Conditions and Limitations.C.20.c • II. Conditions and Limitations.F.10 • II. Applicable Rules and Regulations.C.8.l • II. Applicable Rules and Regulations.C.10.f	Phillips 66 proposes to revise the "Backup Emergency Generator for the HDS Flare Drum Pump" engine description used in the referenced permit conditions to "Emergency Generator Engine (G-8401) for the HDS Flare Drum Backup Pumps."
• II. Conditions and Limitations.F.14	Phillips 66 proposes to add the following sentence after the second sentence in the permit condition to document EPA Method 2510B is an equivalent method that has been approved by MT DEQ: "Phillips 66 has been approved by the department to utilize EPA Method 2510B to determine conductivity."

On April 20, 2022, DEQ received from Phillips 66, an administrative amendment request to reduce allowable emissions from the Fluid Catalytic Cracking Unit. In review of emissions inventory estimation methodologies, Phillips 66 discovered an error in calculated emissions of oxides of nitrogen (NO_X), and carbon monoxide (CO), from the fluid catalytic cracking unit (FCCU). The emissions were calculated to be higher than actual. Because these previously reported emissions from the FCCU were utilized to calculate net emissions increases for previous project(s), Phillips 66 proposed to reduce allowable future emissions from the FCCU to maintain validity of previous conclusions regarding the project(s).

This permitting action placed a limit on CO emissions from the FCCU at 66.0 tons per year, and NO_X to 59.64 tons per year. The CO limit ensured that allowable emissions of CO from the FCCU did not trigger the requirements of the Prevention of Significant Deterioration program as found in ARM 17.8 subchapter 8. The NO_X limit set the potential to emit using a corrected emissions factor. **MAQP #2619-43** replaced MAQP #2619-42.

On May 13, 2022, DEQ received from Phillips 66 an application triggering the Prevention of Significant Deterioration requirements of ARM 17.8 Subchapter 8 (PSD).

Recently, Phillips 66 discovered that an error was made in the calculation of the CO and NO_X emission rates that were reported for the FCCU Stack (EPN 86) in the site's 2018 and 2019 emissions inventories. Those reported emission rates were used as the emissions unit's 2018 and 2019 baseline actual CO and NO_x emission rates in the Billings Projects for 2022 PSD applicability analysis calculations – a project permitted as MAQP #2619-39. However, the corrected 2018 and 2019 CO and NO_x emission rates are lower than the 2018 and 2019 CO and NO_X emission rates that were reported for the emissions unit. Therefore, Phillips 66 is proposing to revise the emissions unit's 2018 and 2019 baseline actual CO and NO_X emission rates used in the project's PSD applicability analysis calculations so that they equal the unit's corrected 2018 and 2019 CO and NO_X emission rates. Also, after further analysis, Phillips 66 is proposing to revise the post-project annual potential to emit CO emission rate for the FCCU Stack. In combination, these updates will have the following impacts on the project's PSD applicability analysis:

- The project will result in a significant net emissions increase in CO, thus making the project subject to PSD review for CO; and

- The project will continue to result in a significant net emissions increase in NO_X, but the increase will be greater than previously calculated and reviewed.

Therefore, DEQ is re-permitting this project, going through PSD for CO, and re-assessing the impacts of increased emissions changes for NO_X. This action does not change the capacities or proposed operation of the units permitted in the Billings Projects for 2022, but the FCCU Stack's allowable emissions of CO and NO_x on an annual basis have been increased to allow for operation at the design capacities that Phillips 66 requires. **MAQP 2619-44** replaces MAQP #2619-43.

MAQP #2619-44 is the most recently issued MAQP. <u>Title</u>

<u>V Operating Permit</u>

Operating Permit #OP2619-00 was issued final and effective on July 9, 2002.

Operating Permit #OP2619-01: A letter from ConocoPhillips dated December 9, 2002, and received by DEQ on December 10, 2002, notified DEQ that Conoco had changed its name to ConocoPhillips. On October 10, 2003, DEQ received a request from ConocoPhillips for an administrative amendment of #OP2619-00 to update Section V.B.3 of the General Conditions incorporating changes to federal Title V rules 40 CFR 70.6(c)(5)(iii)(B) and 70.6(c)(5)(iii)(C) (to be incorporated into Montana's Title V rules at Administrative Rules of Montana (ARM) 17.8.1213) regarding Title V annual compliance certifications. This permit action changed the name on this permit from Conoco to ConocoPhillips and updated Section V.B.3 of the General Conditions. **Operating Permit #OP2619-01** replaced Operating Permit #OP2619-00.

Operating Permit #OP4056-00: On January 10, 2007, DEQ received a renewal application from ConocoPhillips Pipe Line Company. The transportation operations were previously permitted as part of the refinery's Title V Operating Permit #OP2619-01.

However, since there are separate management structures, the facility requested to separate the transportation operations from the refinery in the operating permit. **Operating Permit #OP4056-00** replaced the transportation operations in Operating Permit #OP2619-01.

Operating Permit #OP4056-01: On June 10, 2009, and July 9, 2009, DEQ received requests from ConocoPhillips for an administrative amendment to Operating Permit #OP4056-00. The administrative amendment action changed the responsible officials for the Billings Pipeline and Terminal Operations from John T. Barrett to Amy Gross - Terminal Operations, and Don Miller - Pipeline Operations.

This action required dual signatures for the compliance certification for Billings Pipeline and Terminal Operations. On September 2, 2009, DEQ received an email from ConocoPhillips for additional administrative amendments to Operating Permit #OP4056-00. The additional administrative amendment action updated the mailing address, corrected language in the permit from 'enclosed flare' to 'enclosed firebox within the VCU' (to clarify this equipment is not a flare), correctly identified the small crude offloading tank as #66082 (EU002- Storage Tanks), and added identification numbers to the three ethanol tanks (EU003-Storage Tanks). On September 15, 2009, DEQ received a letter from ConocoPhillips restating the September 2, 2009 administrative amendment requests, but included the dual responsible official signatures on the document. **Operating Permit #OP4056-01** replaced Operating Permit #OP4056-00.

On March 19, 2012, DEQ received notification of a change in responsible official, with Mike Miller replacing Don Miller for the pipeline operations, and Amy Gross remaining as the responsible official representative of the terminal operations.

The notification letter also indicated that ConocoPhillips Company would soon be undertaking an ownership change, and therefore, DEQ could wait to receive the notification to combine the actions into one action from DEQ. DEQ received the name change request on May 1, 2012, requesting the permits be updated to reflect the name change from ConocoPhillips Pipeline Company to Phillips 66 Pipeline LLC. Therefore, Operating Permit #OP4056-01 was replaced with **Operating Permit #OP4056-03**, recognizing the two separate administrative amendment requests were being rolled into one action. Operating Permit #OP4056-03 replaced Operating Permit #OP4056-01.

On December 19, 2012, DEQ received the Title V renewal application from Phillips 66 Pipeline. The notification also provided a request to remove tank #66082 from the operating permit as this tank has been removed from service. **Operating Permit #OP4056-04** replaced Operating Permit #OP4056-03.

On September 4, 2015, DEQ received notification of a change in responsible official, Eli Kliewer replaced Amy Gross. As such, **Operating Permit #OP4056-05** replaced Operating Permit #OP4056-04.

On September 25, 2017, DEQ received notification of a change in responsible officials; Morgan Remus replaced Eli Kliewer (Manager Terminal Division) as responsible official **Operating Permit #OP4056-06** replaced Operating Permit #OP4056-05.

On February 22, 2018, DEQ received the Title V renewal application from Phillips 66 Pipeline. On October 24, 2018, DEQ received a request to update the responsible official from Morgan

Remus to Eli Kliewer. Additionally, Phillips 66 Pipeline requested that EU002 be revised to state that there are 6 ethanol storage tanks at the facility rather than 3 as listed in Section II, Summary of Emission Units. As conveyed in the August 13, 2013, de minimis request, 3 prefabricated 440 bbl capacity ethanol storage tanks were installed in 2013. The ethanol tanks associated with EU002 are identified as TK-145, TK-146, TK-147, TK-149, TK- 150 and TK-151. This renewal action includes the requested updates. **Operating Permit #OP4056-07** replaced Operating Permit #OP4056-06.

D. Current Permit Action

On December 14, 2022, DEQ received a request from Phillips 66 to change the responsible official from Eli Kliewer Jesse McKee. On January 9, 2023, DEQ received a request to change the responsible official from Jesse McKee to two responsible officials, Mr. Clint Loobey, Yellowstone Pipeline Operations Superintendent – Northwest Region, and Mr. Brandon Anderson, Glacier Pipeline Operations Superintendent – Northwest Region. Mr. Loobey and Mr. Anderson are listed as Responsible Officials because they oversee different operations at the Billings site which is permitted under OP#4056. **Operating Permit OP#4056-08** replaces #OP4056-07.

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, DEQ is required to complete a Taking and Damaging Checklist. As required by 2-10-101 through 2-10-105, MCA, DEQ 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 pubic 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, DEQ determined there are no taking or damaging implications associated with this permit action.

F. Compliance Designation

The last Full Compliance Evaluation and Compliance Monitoring Report (FCE/CMR) of the Phillips 66 Pipeline – Billings Pipeline and Terminal Operations was conducted onsite on September 11, 2020 and was found to be in full compliance with all record keeping, reporting, and monitoring requirements.

SECTION II. SUMMARY OF EMISSION UNITS

A. Facility Process Description

The Billings Refinery consists of the main refinery area, where crude is broken down into various petroleum products; a loading rack, where gasoline and distillate is loaded into cargo tanks; a wastewater treatment facility; a tank farm; a coker unit; and the sulfur recovery facility.

This Title V Operating permit covers the bulk loading rack. Processes in these areas include the two gasoline and diesel loading racks (with vapor collection and VCU), propane loading, and ethanol blending. This Title V Operating permit also covers the crude oil unloading and crude oil storage.

B. Emission Units and Pollution Control Device Identification

Emission Unit 001 is the Terminal's Fugitive Emissions associated with the loading rack, and applicable unloading and storage operations, as well as with the crude oil unloading and storage tanks. It is concerned with equipment leaks from valves, connections, open-ended lines, load arms, pumps & meters, as well as minimizing vapor releases associated with gasoline handling.

Emission Unit 002 is Storage Tanks. The crude oil storage tanks must meet requirements of floating roofs with seal systems, or fixed roofs with rooftop vacuum breaker vents. These units undergo regular inspections.

Emission Unit 003 is the Product Bulk Loading. This unit is required to have a vapor collection system as well as a vapor combustion unit for control of VOCs. In addition, there are requirements for valves, flanges, pump seals, and open-ended lines.

C. Categorically Insignificant Sources/Activities

As defined in ARM 17.8.1201, "insignificant emissions unit" means (i) any activity or emissions unit located within a source that has a potential to emit less than 5 tpy of any regulated pollutant; (ii) has a potential to emit less than 500 pounds per year of lead; (iii) has a potential to emit less than 500 pounds per year of hazardous air pollutants listed pursuant to Section 112(b) of the FCAA; and (iv) is not regulated by an applicable requirement, other than a generally applicable requirement that applies to all emission units subject to this subchapter.

Phillips 66 Pipeline provided a full list of emitting units in the February 22, 2018 renewal application and did not indicate any were insignificant sources/activities.

SECTION III. PERMIT CONDITIONS

A. Emission Limits and Standards

Emission limits and standards in this Title V Operating Permit were established from the Montana Air Quality Permit, the Billings/Laurel SIP, NSPS, NESHAP and MACT requirements.

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, do 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, DEQ may request additional testing to determine compliance with the emission limits and standards.

In the case of CEMS and required back-up or alternative methods when the CEMS are not running, the permit states "DEQ shall approve such contingency plans." When such contingency plans are in use and have been submitted, the source will be considered to be in compliance with the contingency plan requirement until DEQ informs Phillips 66 Pipeline otherwise.

C. Test Methods and Procedures

The operating permit may not require testing for all sources if routine monitoring is used to determine compliance, but DEQ 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 the 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 semiannual and annual monitoring reports to DEQ 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 because 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 semiannual and annual reports instead of resubmitting the information in monthly, quarterly, and/or other reports. However, a source must still certify continuous or intermittent compliance with each applicable requirement annually.

F. Public Notice

As it was an administrative amendment request received on December 14, 2022, no public notice was required.

SECTION IV. FUTURE PERMIT CONSIDERATIONS

A. MACT Standards

40 CFR 63, Subparts R, CC, and EEEE (Organic Liquids Distribution (non-gasoline)) are applicable to this facility. 40 CFR 63 Subpart BBBBBB does not apply to #OP4056-07 because the sources covered under #OP4056-07 are "major" under this permit and therefore cannot also be considered 'area" sources. 40 CFR 63 Subpart CCCCCC is not applicable because it deals only with the dispensing facilities typically identified as "gas stations".

B. NESHAP Standards

As of September 28, 2009, 40 CFR 61, Subpart M is applicable to this facility. DEQ is unaware of any proposed or pending NESHAP standard that may be promulgated that will affect the facility.

C. NSPS Standards

40 CFR 60, Subpart A, VV, XX and GGG are applicable to this facility. The facility must comply with Subpart VV requirements as part of 40 CFR 63, Subpart CC and with Subpart XX requirements as part of 40 CFR 63, Subpart R. DEQ is unaware of any proposed or pending NSPS standard that may be promulgated that will affect the facility.

D. Risk Management Plan

DEQ is not aware of any substances stored at this facility which exceeds the minimum threshold quantities for any regulated substance listed in 40 CFR 68.115. Therefore, this facility is not 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 three 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. CAM Applicability

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 emissions of the applicable regulated air pollutant that is greater than major source thresholds.

Phillips 66 Pipeline does not currently have any emitting units that meet all the applicability criteria in ARM 17.8.1503 under Operating Permit #OP4056-07 and is therefore not currently required to develop a CAM Plan for the Billings Pipeline and Terminal Operations.

F. PSD and Title V Greenhouse Gas Tailoring Rule

Under the Tailoring Rule, any PSD action (either a new major stationary source or a major modification at a major stationary source) taken for a pollutant or pollutants other than GHG that would become final on or after January 2, 2011 would be subject to PSD permitting requirements for GHG if the GHG increases associated with that action were at or above 75,000 TPY of carbon dioxide equivalent (CO_2e) and greater than 0 TPY on a mass basis. Similarly, if such action were taken, any resulting requirements would be subject to inclusion in the Title V Operating Permit. Facilities which hold Title V permits due to criteria pollutant emissions over 100 TPY would need to incorporate any GHG applicable requirements into their operating permits for any Title V action that would have a final decision occurring on or after January 2, 2011.

Starting on July 1, 2011, PSD permitting requirements would be triggered for modifications that were determined to be major under PSD based on GHG emissions alone, even if no other pollutant triggered a major modification. In addition, sources that are not considered PSD major sources based on criteria pollutant emissions would become subject to PSD review if their facility-wide potential emissions equaled or exceeded 100,000 TPY of CO_2e and 100 or 250 TPY of GHG on a mass basis depending on their listed status in ARM 17.8.801(22) and they undertook a permitting action with increases of 75,000 TPY or more of CO_2e and greater than 0 TPY of GHG on a mass basis. With respect to Title V, sources not currently holding a Title V permit that have potential facility-wide emissions equal to or exceeding 100,000 TPY of CO_2e and 100 TPY of GHG on a mass basis would be required to obtain a Title V Operating Permit.

The Supreme Court of the United States (SCOTUS), in its *Utility Air Regulatory Group v. EPA* decision on June 23, 2014, ruled that the Clean Air Act neither compels nor permits EPA to require a source to obtain a PSD or Title V permit on the sole basis of its potential emissions of GHG. SCOTUS also ruled that EPA lacked the authority to tailor the Clean Air Act's unambiguous numerical thresholds of 100 or 250 TPY to accommodate a CO_2e threshold of 100,000 TPY. SCOTUS upheld that EPA reasonably interpreted the Clean Air Act to require sources that would need PSD permits based on their emission of conventional pollutants to comply with BACT for GHG. As such, the Tailoring Rule has been rendered invalid and sources cannot become subject to PSD or Title V regulations based on GHG emissions alone. Sources that must undergo PSD permitting due to pollutant emissions other than PSD may still be required to comply with BACT for GHG emissions.