State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of
Environmental Quality

Tim Davis
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQE-AN101190108-26

April 14, 2026

Lauren Vander Werff
Chevron Products Company - Salt Lake Refinery
685 South Chevron Way
North Salt Lake, UT 84054
LVanderWerff@chevron.com

Dear Ms. Vander Werff:

Re: Approval Order: Administrative Amendment to Approval Order DAQE-AN101190107-24 to Include Specific Requirements from the Consent Decree and to Update $PM_{2.5}$ SIP Conditions
Project Number: N101190108

The attached Approval Order (AO) is issued pursuant to the Notice of Intent (NOI) received on September 11, 2025. Chevron Products Company - Salt Lake Refinery must comply with the requirements of this AO, all applicable state requirements (R307), and Federal Standards.

The project engineer for this action is **John Jenks**, who can be contacted at (385) 306-6510 or jjenks@utah.gov. Future correspondence on this AO should include the engineer's name as well as the DAQE number shown on the upper right-hand corner of this letter.

Sincerely,

Bryce C. Bird
Director

BCB:JJ:jg

cc: Salt Lake County Health Department
EPA Region 8

STATE OF UTAH
Department of Environmental Quality
Division of Air Quality

APPROVAL ORDER
DAQE-AN101190108-26
Administrative Amendment to Approval Order DAQE-AN101190107-24 to Include Specific Requirements from the Consent Decree and to Update $PM_{2.5}$ SIP Conditions

Prepared By
John Jenks, Engineer
(385) 306-6510
jjenks@utah.gov

Issued to
Chevron Products Company - Salt Lake Refinery

Issued On
April 14, 2026

Issued By

Bryce C. Bird
Director
Division of Air Quality

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GENERAL INFORMATION

CONTACT/LOCATION INFORMATION

Owner Name
Chevron Products Company - Salt Lake Refinery

Source Name
Chevron Products Company - Salt Lake Refinery

Mailing Address
685 South Chevron Way
North Salt Lake, UT 84054

Physical Address
685 South Chevron Way
North Salt Lake, UT 84054

Source Contact
Name: Evan Hunter
Phone: (801) 539-7238
Email: evan.hunter@chevron.com

UTM Coordinates
422,270 m Easting
4,519,770 m Northing
Datum NAD83
UTM Zone 12

SIC code 2911 (Petroleum Refining)

SOURCE INFORMATION

General Description
Chevron Products Company - Salt Lake Refinery is a petroleum refinery with a nominal capacity of approximately 50,000 barrels per day of crude oil. The source consists of one fluidized catalytic cracking unit (FCCU), a delayed coking unit, a catalytic reforming unit, hydrotreating units and two sulfur recovery units. The source also has assorted heaters, boilers, cooling towers, storage tanks, flares, and similar fugitive emissions. The refinery operates with a flare gas recovery system on two of its three hydrocarbon flares.

NSR Classification
Administrative Amendment

Source Classification
Located in Northern Wasatch Front O3 NAA
Davis County
Airs Source Size: A

Applicable Federal Standards
NSPS (Part 60), A: General Provisions
NSPS (Part 60), Db: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
NSPS (Part 60), J: Standards of Performance for Petroleum Refineries
NSPS (Part 60), Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007
NSPS (Part 60), K: Standards of Performance for Storage Vessels for Petroleum Liquids for

Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978
NSPS (Part 60), Ka: Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984
NSPS (Part 60), Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984, and On or Before October 4, 2023
NSPS (Part 60), GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006
NSPS (Part 60), QQQ: Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems
NSPS (Part 60), IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
NSPS (Part 60), JJJJ: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
NESHAP (Part 61), A: General Provisions
NESHAP (Part 61), M: National Emission Standard for Asbestos
NESHAP (Part 61), FF: National Emission Standard for Benzene Waste Operations
MACT (Part 63), A: General Provisions
MACT (Part 63), CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries
MACT (Part 63), UUU: National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units
MACT (Part 63), EEEE: National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)
MACT (Part 63), ZZZZ: National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
MACT (Part 63), DDDDD: National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters
MACT (Part 63), GGGGG: National Emission Standards for Hazardous Air Pollutants: Site Remediation
Title V (Part 70) Major Source

Project Description

Chevron Products Company (Chevron) requested an administrative update to its most recent refinery AO (DAQE-AN101190107-24 dated December 3, 2024). This AO change would update the $PM_{2.5}$ SIP conditions to the most recently approved version of the SIP. In addition, certain requirements of Chevron's Consent Decree also need to be incorporated into the language of the AO - primarily definitions in the equipment list and some minor changes in rule references, but also to include a clarification in stack testing frequency. On March 5, 2026, Chevron submitted an addendum to remove one piece of equipment with a corresponding reduction in emissions. This project does not include any new requirements or relax any existing requirements on the facility.

SUMMARY OF EMISSIONS

The emissions listed below are an estimate of the total potential emissions from the source. Some rounding of emissions is possible.

Criteria Pollutant	Change (TPY)	Total (TPY)
CO_2 Equivalent	-6.27	988776.40
Carbon Monoxide	-0.01	990.59
Nitrogen Oxides	-0.03	763.54
Particulate Matter - PM_{10}	0	260.95
Particulate Matter - $PM_{2.5}$	0	109.97
Sulfur Dioxide	0	383.30
Volatile Organic Compounds	-0.03	1241.86

Hazardous Air Pollutant	Change (lbs/yr)	Total (lbs/yr)
Acetaldehyde (CAS #75070)	0	165
Acrolein (CAS #107028)	0	239
Ethyl Benzene (CAS #100414)	0	225
Formaldehyde (CAS #50000)	0	1034
Generic HAPs (CAS #GHAPS)	0	254
Hexane (CAS #110543)	0	25309
Xylenes (Isomers And Mixture) (CAS #1330207)	0	350
	Change (TPY)	**Total (TPY)**
Total HAPs	0	13.79

SECTION I: GENERAL PROVISIONS

I.1	All definitions, terms, abbreviations, and references used in this AO conform to those used in the UAC R307 and 40 CFR. Unless noted otherwise, references cited in these AO conditions refer to those rules. [R307-101]
I.2	The limits set forth in this AO shall not be exceeded without prior approval. [R307-401]
I.3	Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved. [R307-401-1]
I.4	All records referenced in this AO or in other applicable rules, which are required to be kept by the owner/operator, shall be made available to the Director or Director's representative upon request, and the records shall include the two-year period prior to the date of the request. Unless otherwise specified in this AO or in other applicable state and federal rules, records shall be kept for a minimum of five years. [R307-401-8]
I.5	At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this AO, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Director which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded. [R307-401-4]

I.6	The owner/operator shall comply with UAC R307-107. General Requirements: Breakdowns. [R307-107]
I.7	The owner/operator shall comply with UAC R307-150 Series. Emission Inventories. [R307-150]

SECTION II: PERMITTED EQUIPMENT

II.A THE APPROVED EQUIPMENT

II.A.1	**Main Refinery** Chevron Salt Lake Refinery
II.A.2	**F-11005** Boiler #11005 (Boiler #5) Rating: 171 MMBtu/hr Control: Low-NO_x NSPS Applicability: Subpart A, Subpart Db (NO_x), Subpart J (SO_2)
II.A.3	**F-11006** Boiler #11006 (Boiler #6) Rating: 171 MMBtu/hr Control: Low-NO_x NSPS Applicability: Subpart A, Subpart Db (NO_x), Subpart Ja (SO_2)
II.A.4	**F-11007** Boiler #11007 (Boiler #7) Rating: 225 MMBtu/hr Control: Low-NO_x and Flue Gas Recirculation (FGR) NSPS Applicability: Subpart A, Subpart Db (NO_x), Subpart Ja (SO_2)
II.A.5	**16001** Cooling Tower #16001
II.A.6	**16002** Cooling Tower #16002
II.A.7	**16003** Cooling Tower #16003
II.A.8	**16004** Cooling Tower #16004 (Grandfathered)
II.A.9	**F-21001** Crude Unit Furnace #F-21001 Rating: 130 MMBtu/hr Control: Low-NO_x NSPS Applicability: Subpart A, Subpart J

II.A.10	**F-21002** Crude Unit Furnace #F-21002 Rating: 115.1 MMBtu/hr Control: Low-NO_x NSPS Applicability: Subpart A, Subpart J
II.A.11	**F-32021** FCC Furnace F-32021 Rating: 48.2 MMBtu/hr NSPS Applicability: Subpart A, Subpart J
II.A.12	**F-32023** FCC Furnace F-32023 Rating: 48.2 MMBtu/hr NSPS Applicability: Subpart A, Subpart J
II.A.13	**F-71010** HDN Furnace F-71010 Rating: 15.6 MMBtu/hr NSPS Applicability: Subpart A, Subpart J
II.A.14	**F-71030** HDN Furnace F-71030 Rating: 36.3 MMBtu/hr NSPS Applicability: Subpart A, Subpart J
II.A.15	**F-35001** Reformer Furnace F-35001 Rating: 52.3 MMBtu/hr NSPS Applicability: Subpart A, Subpart J
II.A.16	**F-35002** Reformer Furnace F-35002 Rating: 45 MMBtu/hr NSPS Applicability: Subpart A, Subpart J
II.A.17	**F-35003** Reformer Furnace F-35003 Rating: 31.7 MMBtu/hr NSPS Applicability: Subpart A, Subpart J
II.A.18	**Alkylation Unit** Includes: Alkylation Furnace F-36017 Rating: 108 MMBtu/hr Control: Low-NO_x NSPS Applicability: Subpart A, Subpart J
II.A.19	**F-70001** Coker Furnace F-70001 Rating: 139.2 MMBtu/hr NSPS Applicability: Subpart A, Subpart J
II.A.20	**F-64010** HDS Furnace F-64010 Rating: 19 MMBtu/hr Control: Low-NO_x NSPS Applicability: Subpart A, Subpart J

II.A.21	**F-64011** HDS Furnace F-64011 Rating: 27.3 MMBtu/hr Control: Low-NO_x NSPS Applicability: Subpart A, Subpart J
II.A.22	**F-66100** VGO Furnace F-66100 Rating: 40 MMBtu/hr Control: Low-NO_x NSPS Applicability: Subpart A, Subpart J
II.A.23	**F-66200** VGO Furnace F-66200 Rating: 66 MMBtu/hr Control: Low-NO_x NSPS Applicability: Subpart A, Subpart J
II.A.24	**SRU/TGTU/TGI #1** SRU and Tail Gas Incinerator #1 NSPS Applicability: Subpart A, Subpart Ja
II.A.25	**SRU/TGTU/TGI #2** Sulfur Recovery Unit (SRU) and Tail Gas Incinerator #2 NSPS Applicability: Subpart A, Subpart Ja
II.A.26	**Catalyst Regenerator** FCCU and Catalyst Regenerator
II.A.27	**F61312** Flameless Thermal Oxidizer
II.A.28	**Coker Flare (Flare #1)** Coker Flare (Control/Safety Device)
II.A.29	**FCCU Flare (Flare #2)** FCCU Flare (Control/Safety Device)
II.A.30	**Alkylation Flare (Flare #3)** Alkylation Flare (Control/Safety Device)
II.A.31	**Diesel-powered back-up equipment:** A. Second North Substation Generator: One Emergency Generator Engine Rating: 750 hp. Generator Rating: 500 kW B. #1 CWT: One Emergency Cooling Water Pump Engine Rating: 665 hp. C. HDN Substation: One Emergency Generator Engine Rating: 601 hp. Generator Rating: 400 kW D. VGO: One Emergency Generator Engine Rating: 755 hp. (max). Generator Rating: 500 kW

II.A.32	E. Crude Substation: One Backup Generator Engine Rating: 900 hp. Generator Rating: 600 kW F. Third North Substation: One Backup Emergency Generator Engine Rating: 1490 hp. Generator Rating: 1,111 kW G. Admin Building: One Backup Generator Engine Rating: 2,220 hp. Generator Rating: 1,250 kW H. TCLR: One Backup Generator Engine Rating: 197 hp. Generator Rating: 125 kW I. North Tank Field: One Backup Generator Engine Rating: 896 hp. Generator Rating: 600 kW
II.A.33	J. WWTP: One Backup Generator Engine Rating: 896 hp. Generator Rating: 600 kW K. Alky: One Emergency Generator Engine Rating: 752 hp. Generator Rating: 500 kW L. Boiler Plant: Two Compressors Engine Rating: 524 hp. each M. FCC MCC: One Emergency Generator Engine Rating: 895 hp. Generator Rating: 600 kW N. Three Fire Water Pumps Engine Rating: 950 hp. (maximum design at 2100 rpm) each.
II.A.34	O. One Canal Fire Water Emergency Generator Engine Rating: 462 hp. Generator Rating: 300 kW P. One Reformer Substation Emergency Generator Engine Rating: 616 hp. Generator Rating: 400 kW
II.A.35	**Natural gas-powered backup equipment** A. One Emergency Generator Engine Rating: 50 hp. Generator Rating: 30 kW
II.A.36	**K35001, K35002, K35003** Three Reformer Compressor Drivers Rating: 16 MMBtu/hr each Fuel: Refinery Fuel Gas
II.A.37	**Amine Unit #1** Amine Unit #1
II.A.38	**Amine Unit #2** Amine Unit #2
II.A.39	**K36067** Lime Loading Facility K36067
II.A.40	**FCC Fines Bin**

SECTION II: SPECIAL PROVISIONS

II.B REQUIREMENTS AND LIMITATIONS

II.B.1	**Source-wide Requirements**
II.B.1.a	Except as otherwise stated in this AO, the owner/operator shall use only plant gas or purchased natural gas as a primary fuel. Plant Coke may be burned in the FCC Catalyst Regenerator. Torch oil may be burned in the FCC Catalyst Regenerator to assist in starting, restarting, hot standby, or to maintain regenerator heat balance. If any other fuel is to be used, an AO shall be required. [Consent Decree, R307-401]
II.B.1.b	All petroleum refineries in or affecting any $PM_{2.5}$ nonattainment area or any PM_{10} nonattainment or maintenance area shall reduce the H_2S content of the refinery plant gas to 60 ppm or less as described in 40 CFR 60.102a. Compliance shall be based on a rolling average of 365 days. The owner/operator shall comply with the fuel gas monitoring requirements of 40 CFR 60.107a and the related recordkeeping and reporting requirements of 40 CFR 60.108a. As used herein, refinery "plant gas" shall have the meaning of "fuel gas" as defined in 40 CFR 60.101a and may be used interchangeably. For natural gas, compliance is assumed while the fuel comes from a public utility. [SIP Section IX.H.11.g.ii]
II.B.1.c	No petroleum refineries in or affecting any $PM_{2.5}$ nonattainment area or PM_{10} nonattainment or maintenance area shall be allowed to burn liquid fuel oil in stationary sources except during natural gas curtailments or as specified below: A. The use of diesel fuel meeting the specifications of 40 CFR 1090.305 in standby or emergency equipment is exempt from the limitation above and is allowed in standby or emergency equipment at all times. B. Plant coke may be burned in the FCC Catalyst Regenerator. [R307-401-8(1)(a), SIP Section IX.H.11.g.vii, SIP Section IX.H.12.d.iv]
II.B.1.d	The owner/operator shall not allow visible emissions to exceed the opacity limits set in R307-309. [R307-309]

II.B.1.e	The owner/operator shall ensure for all stack testing performed: Unless otherwise specified by federal rule, the owner/operator shall provide a pre-test protocol at least 30 days prior to the test. A pretest conference between the owner/operator, the tester, and the Director shall be held if directed by the Director. The emission point shall conform to the requirements of 40 CFR 60, Appendix A, Method 1. Occupational Safety and Health Administration (OSHA) approved access shall be provided to the test location. The throughput rate during stack testing shall be no less than 90% of the rated throughput or 90% of the highest monthly throughput achieved in the previous three years, whichever is the least. If the desired throughput rate is not achieved at the time of testing, the achieved throughput rate +10% will become the maximum allowable throughput rate. Additional testing shall be required, following the same procedure, to establish a higher throughput rate if the existing maximum allowable throughput rate is to be exceeded. Where appropriate, the following test methods shall be used, although other EPA-approved test methods acceptable to the Director can be substituted and approved through the pre-test protocol: Volumetric flow rate - 40 CFR 60, Appendix A, Method 2 SO_2 emissions - 40 CFR 60, Appendix A, Method 6C NO_x emissions - 40 CFR 60, Appendix A, Method 7E PM_{10} and $PM_{2.5}$ emissions - 40 CFR 51, Appendix M, Methods 201a and 202 To determine mass emission rates (lbs/hr, etc.), the pollutant concentration, as determined by the appropriate methods above, shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Director to give the results in the specified units of the emission limitation. [R307-401]
II.B.1.f	Source-wide combined emissions of PM_{10} shall not exceed 0.715 tons per day (tpd). [SIP Section IX.H.2.d.i]

II.B.1.f.1	Compliance with the source-wide PM_{10} Cap shall be determined for each day as follows: A. Total 24-hour PM_{10} emissions for the emission points shall be calculated by adding the daily results of the PM_{10} emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers and the FCCU to arrive at a combined daily PM_{10} emission total. B. For purposes of this subsection, a "day" is defined as a period of 24 hours commencing at midnight and ending at the following midnight. C. Daily natural gas and plant gas consumption shall be determined through the use of flow meters. D. Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources. E. The equation used to determine emissions for the boilers and furnaces shall be as follows: Emission Factor (lb/MMscf) * Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton) F. Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions. [SIP Section IX.H.2.d.i.C]
II.B.1.f.2	The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing, the default emission factors to be used are as follows: A. Natural gas: Filterable PM_{10}: 1.9 lb/MMscf Condensable PM_{10}: 5.7 lb/MMscf B. Plant gas: Filterable PM_{10}: 1.9 lb/MMscf Condensable PM_{10}: 5.7 lb/MMscf C. Diesel fuel: shall be determined from the latest edition of AP-42 or other EPA-approved methods. D. Cooling Towers: shall be determined from the latest edition of AP-42 or other EPA-approved methods. E. FCC Stack: The PM_{10} emission factors shall be based on the most recent stack test and verified by parametric monitoring. F. Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel. [SIP Section IX.H.2.d.i.A]

II.B.1.f.3	The default emission factors listed above apply until such time as stack testing is conducted. Initial PM_{10} stack testing on the FCC stack has been performed and shall be conducted at least once every three years from the date of the last stack test. Stack testing shall be performed as outlined in Condition II.B.1.e. [SIP Section IX.H.2.d.i.B]
II.B.1.g	Source-wide combined emissions of NO_x shall not exceed 2.1 tons per day (tpd) and 766.5 tons per rolling 12-month period. [SIP Section IX.H.2.d.ii]
II.B.1.g.1	Compliance with the source-wide NO_x Cap shall be determined for each day as follows: A. Total 24-hour NO_x emissions shall be calculated by adding the emissions for each emitting unit. B. The emissions for each emitting unit shall be calculated by multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each fuel combusted at each affected unit by the associated emission factor and summing the results. C. A NO_x CEM shall be used to calculate daily NO_x emissions from the FCCU. D. A NO_x CEM shall be used to calculate daily NO_x emissions from Boiler #7. E. For purposes of this subsection, a "day" is defined as a period of 24 hours commencing at midnight and ending at the following midnight. F. Daily natural gas and plant gas consumption shall be determined through the use of flow meters. G. Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources. H. Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions. [SIP Section IX.H.2.d.ii.C]
II.B.1.g.2	The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. Unless adjusted by performance testing, the default emission factors to be used are as follows: A. Natural gas: shall be determined from the latest edition of AP-42 or other EPA-approved methods. B. Plant gas: shall be assumed equal to natural gas. C. Diesel fuel: shall be determined from the latest edition of AP-42 or other EPA-approved methods. D. Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel. [SIP Section IX.H.2.d.ii.A]

II.B.1.g.3	The default emission factors listed above apply until such time as stack testing is conducted. Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr has been performed and shall be conducted at least once every three years from the date of the last stack test. At that time a new flow-weighted average emission factor in terms of lbs/MMbtu shall be derived for each combustion type listed above. Stack testing shall be performed as outlined in Condition II.B.1.e. [SIP Section IX.H.2.d.ii.B]
II.B.1.h	Source-wide combined emissions of SO_2 shall not exceed 1.05 tons per day (tpd) and 383.3 tons per rolling 12-month period. [SIP Section IX.H.2.d.iii]
II.B.1.h.1	Compliance with the source-wide SO_2 Cap shall be determined for each day as follows: A. Total daily SO_2 emissions shall be calculated by adding the daily SO_2 emissions for natural gas and plant fuel gas combustion to those from the FCC and SRU stacks. B. Daily natural gas and plant gas consumption shall be determined through the use of flow meters. C. Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources. D. Results shall be tabulated for each day, and records shall be kept which include CEM readings for H_2S (averaged for each one-hour period), all meter readings (in the appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel oil is burned), and the calculated emissions. E. For purposes of this subsection, a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight. [SIP Section IX.H.2.d.iii.B]
II.B.1.h.2	The emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. The default emission factors to be used are as follows: A. FCCU: The emission rate shall be determined by the FCC SO_2 CEM. B. SRUs: The emission rate shall be determined by multiplying the sulfur dioxide concentration in the flue gas by the flow rate of the flue gas. The sulfur dioxide concentration in the flue gas shall be determined by CEM. C. Natural gas: EF = 0.60 lb/MMscf D. Fuel oil: The emission factor to be used for combustion shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or EPA-approved equivalent acceptable to the Director, and the density of the fuel oil, as follows: EF (lb SO_2/k gal) = density (lb/gal) * (1000 gal/k gal) * wt.% S/100 * (64 lb SO_2/32 lb S) E. Plant gas: the emission factor shall be calculated from the H_2S measurement obtained from the H_2S CEM. F. Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel. [SIP Section IX.H.2.d.iii.A]

II.B.1.i	The owner/operator shall submit a report of any deviation from the applicable requirements of SIP Subsection IX.H.11, including those attributable to upset conditions, the probable cause of such deviations, and any corrective actions or preventative measures taken. The report shall be submitted to the Director no later than 24 months following the deviation or earlier if specified by an underlying applicable requirement. Deviations due to breakdowns shall be reported according to the breakdown provisions of R307-107. [SIP Section IX.H.11.c.iii]
II.B.2	**Conditions on Process Heaters/Furnaces and Boilers**
II.B.2.a	NO_x emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations. A. F-11005 Boiler #5 0.20 lb/MMBtu. B. F-11006 Boiler #6 0.20 lb/MM Btu. C. F-11007 Boiler #7 0.20 lb/MM Btu. D. F-21001 Crude Furnace #1 0.09 lb/MMBtu. E. F-21002 Crude Furnace #2 0.09 lb/MMBtu. F. F-32021 FCC Furnace #1 0. 17 lb/MMBtu. G. F-32023 FCC Furnace #2 0.17 lb/MMBtu. H. F-35001 Reformer Furnace F-1 0.17 lb/MMBtu. I. F-35002 Reformer Furnace F-2 0.17 lb/MMBtu. J. F-36017 Alkylation Furnace 0.12 lb/MM Btu. K. F-70001 Coker Furnace 0.16 lb/MMBtu. L. F-66100 VGO Furnace # I 0.05 lb/MM Btu. M. F-66200 VGO Furnace #2 0.05 lb/MM Btu. [SIP Section IX.H.12.d.i]

II.B.2.a.1	A. Initial NO_x stack testing has been performed for the following units: F-11005 Boiler #5, F-11006 Boiler #6, F-21001 Crude Furnace #1, F-21002 Crude Furnace #2, F-36017 Alkylation Furnace, and F-70001 Coker Furnace. For these units stack testing shall be conducted at least once within a three year period from the date of the last stack test. Stack testing shall be performed as outlined in $PM_{2.5}$ SIP Section IX.H.11.e. B. For the F-11007 Boiler #7. NO_x emissions shall be monitored by CEMs to determine compliance. Compliance shall be determined on a 30-day rolling average. The CEM shall operate as outlined in $PM_{2.5}$ SIP Section IX.H.11.f. C. Initial compliance testing for F-66100 VGO furnace #1 and F-66200 VGO Furnace #2 is required. The initial test shall be performed no later than December 31, 2025. After the initial compliance test, stack testing shall be performed at least once within a three year period from the date of the last stack test. Stack testing shall be performed as outlined in $PM_{2.5}$ SIP Section lX.H.11.e. D. A stack testing port shall be installed for F-32021 FCC Furnace #1, F-32023 FCC Furnace #2, F-35001 Reformer Furnace F-1, and F-35002 Reformer Furnace #2. Initial compliance testing shall be performed no later than December 31, 2027. After the initial compliance test, stack testing shall be performed at least once within a three year period from the date of the last stack test. Stack testing shall be performed as outlined in $PM_{2.5}$ SIP Section IX.H.11.e. E. In lieu of the stack testing requirements listed above, any units equipped with a CEMS shall determine compliance with the emission limits by the CEMs. For units equipped with CEMs, compliance shall be determined on a 30-day rolling average. The CEMs shall operate as outlined in $PM_{2.5}$ SIP Section IX.H.11.f. [SIP Section IX.H.12.d.ii - IX.H.12.d.iv]
II.B.3	**Conditions on Boiler #11005 (Boiler #5)**
II.B.3.a	NO_x emissions shall not exceed the following rate on a 30-day rolling average basis: [NSPS Db §60.44b(b) and §60.44b(i)] En = ((0.1 x Hgo) + (0.2 x Hr)) / (Hgo + Hr) Where: En = NO_x emission limit (lb/MMbtu) Hgo = 30-day heat input from combustion of natural gas or distillate oil Hr = 30-day heat input from combustion of any other fuel [40 CFR 60 Subpart Db]
II.B.3.a.1	The NO_x emission rate shall be predicted based on excess O_2 in the flue gas and by boiler loading as specified in a plan submitted to and approved by the Director [NSPS Db §60.48b(g)(2)]. Predicted NO_x emission rate shall be evaluated at least every three years through testing as outlined in Condition II.B.1.e. [40 CFR 60 Subpart Db]

II.B.4	**Conditions on Boiler #11006 (Boiler #6)**
II.B.4.a	NO_x emissions shall not exceed the following rate on a 30-day rolling average basis: [NSPS Db §60.44b(b) and §60.44b(i)] En = ((0.1 x Hgo) + (0.2 x Hr)) / (Hgo + Hr) Where: En = NO_x emission limit (lb/MMbtu) Hgo = 30-day heat input from combustion of natural gas or distillate oil Hr = 30-day heat input from combustion of any other fuel. [40 CFR 60 Subpart Db]
II.B.4.a.1	The NO_x emission rate shall be predicted based on excess O_2 in the flue gas and by boiler loading as specified in a plan submitted to and approved by the Director [NSPS Db §60.48b(g)(2)]. Predicted NO_x emission rate shall be evaluated at least every three years through testing as outlined in Condition II.B.1.e. [40 CFR 60 Subpart Db]
II.B.5	**Conditions on the SRUs**
II.B.5.a	All petroleum refineries in or affecting any $PM_{2.5}$ nonattainment or maintenance area or any PM_{10} nonattainment or maintenance area shall require: A. Sulfur removal units/plants (SRUs) that are at least 95% effective in removing sulfur from the streams fed to the unit; or B. SRUs that meet the SO_2 emission limitations listed in 40 CFR 60.102a(f)(1) or 60.102a(f)(2) as appropriate. [SIP Section IX.H.1.g.iii.A]
II.B.5.b	The owner/operator shall process amine acid gas and sour water stripper acid gas in the SRU(s). [SIP Section IX.H.1.g.iii.B]
II.B.5.b.1	Compliance shall be demonstrated by daily monitoring of flows to the SRU(s). Compliance shall be determined on a rolling 30-day average. [SIP Section IX.H.1.g.iii.C]
II.B.6	**Conditions on SRU and Tail Gas Treatment Unit #1**
II.B.6.a	Emissions of SO_2 from SRU #1 shall not exceed 0.242 tons/day. [R307-401]

II.B.6.a.1	Daily sulfur dioxide emissions shall be determined by multiplying the sulfur dioxide concentration in the flue gas by the mass flow of the flue gas. The sulfur dioxide concentration in the flue gas shall be determined by a CEM that meets or exceeds the requirements contained in 40 CFR 60, Appendix B: Performance Specification 2. The monitor shall be maintained and calibrated in accordance with R307-170, UAC. 40 CFR 60 Methods 2, 3A, and 6C shall be used to determine relative accuracy. If a new monitor is installed, an initial performance evaluation shall be performed within 30 days of installation. The performance evaluation shall be conducted and data reduced in accordance with the methods and procedures contained in 40 CFR 60, Appendix B: Performance Specification 2. Notification must be made to the Director prior to conducting the performance evaluation. Whenever the SO_2 CEM is bypassed for short periods, SO_2 CEM data from the previous three days will be averaged and used as an emission factor to determine emissions. The mass flow rate of the flue gas shall be determined by a volumetric flow measurement device that meets or exceeds the requirements contained in 40 CFR 52 Appendix E. An annual relative accuracy test audit shall be conducted, and quarterly reports submitted, in accordance with the procedures outlined in R307-170, UAC, and 40 CFR 52 Appendix E. If a new volumetric flow measurement device is installed, an initial performance evaluation shall be performed within 30 days of installation. The performance evaluation shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 52 Appendix E. Notification must be made to the Director prior to conducting the performance evaluation. The source shall maintain records of the SO_2 concentration, the mass flow rate, and the resulting calculated emissions. Records of all CEM calibrations shall also be maintained. [R307-401]
II.B.6.b	Emissions of SO_2 from SRU #1 shall not exceed 88.5 tons/yr. [R307-401]
II.B.6.b.1	Compliance shall be determined on a 12-month rolling average. Each month, the SO_2 emissions calculated to show compliance with the daily limitations for the previous month shall be summed to give a monthly emission total. This shall be added to the previous 11 months' emission totals to give the new 12-month rolling total. [R307-401]
II.B.6.c	The owner/operator shall continue to route or re-route all sulfur pit emissions so that they are eliminated, controlled, or included and monitored as part of the SRU's emissions subject to the emissions limits of II.B.5. [Consent Decree]
II.B.7	**Conditions on SRU and Tail Gas Treatment Unit #2**
II.B.7.a	Emissions of SO_2 from SRU #2 shall not exceed 0.268 tons/day. [R307-401]

II.B.7.a.1	Daily sulfur dioxide emissions shall be determined by multiplying the sulfur dioxide concentration in the flue gas by the mass flow of the flue gas. The sulfur dioxide concentration in the flue gas shall be determined by a CEM that meets or exceeds the requirements contained in 40 CFR 60, Appendix B: Performance Specification 2. The monitor shall be maintained and calibrated in accordance with R307- 170, UAC. 40 CFR 60 Methods 2, 3A, and 6C shall be used to determine relative accuracy. If a new monitor is installed, an initial performance evaluation shall be performed within 30 days of installation. The performance evaluation shall be conducted and data reduced in accordance with the methods and procedures contained in 40 CFR 60, Appendix B: Performance Specification 2. Notification must be made to the Director prior to conducting the performance evaluation. Whenever the SO_2 CEM is bypassed for short periods, SO_2 CEM data from the previous three days will be averaged and used as an emission factor to determine emissions. The mass flow rate of the flue gas shall be determined by a volumetric flow measurement device that meets or exceeds the requirements contained in 40 CFR 52 Appendix E. An annual relative accuracy test audit shall be conducted, and quarterly reports submitted, in accordance with the procedures outlined in R307-170, UAC, and 40 CFR 52 Appendix E. If a new volumetric flow measurement device is installed, an initial performance evaluation shall be performed within 30 days of installation. The performance evaluation shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 52 Appendix E. Notification must be made to the Director prior to conducting the performance evaluation. The source shall maintain records of the SO_2 concentration, the mass flow rate, and the resulting calculated emissions. Records of all CEM calibrations shall also be maintained. [R307-401]
II.B.7.b	Emissions of SO_2 from SRU #2 shall not exceed 97.7 tons/yr. [R307-401]
II.B.7.b.1	Compliance shall be determined on a 12-month rolling average. Each month, the SO_2 emissions calculated to show compliance with the daily limitations for the previous month shall be summed to give a monthly emission total. This shall be added to the previous 11 months' emission totals to give the new 12-month rolling total. [R307-401]
II.B.7.c	The owner/operator shall continue to route or re-route all sulfur pit emissions so that they are eliminated, controlled, or included and monitored as part of the SRU's emissions subject to the emissions limits of II.B.6. [Consent Decree]

II.B.8	**Conditions on the FCC and Catalyst Regenerator**
II.B.8.a	Emissions of SO_2 from the FCCU Regenerator Vent shall not exceed the following rates and concentrations: A. 25 ppmvd SO_2 @ 0% O_2 on a 365-day rolling average. B. 50 ppmvd SO_2 @ 0% O_2 on a 7-day rolling average. C. 50 tons of SO_2 on a 12-month rolling average. D. 0.28 tons of SO_2 per day. SO_2 emissions during periods of startup, shutdown, or malfunction shall not be used in determining compliance with the emission limit of 50 ppmvd SO_2 @ 0% O_2 on a 7-day rolling average basis. The SO_2 short-term limit listed in B above shall exclude FCCU feed hydrotreater outages if Chevron complies with an EPA-approved hydrotreater outage plan and is maintaining and operating the FCCU in a manner consistent with good air pollution control practices. It shall apply at all other times the FCCU is in operation. In addition, in the event that the source asserts that the basis for a specific Hydrotreater Outage is a shutdown (where no catalyst changeout occurs) required by ASME pressure vessel requirements or applicable state boiler requirements, the source shall submit a report to EPA that identifies the relevant requirements and justifies the permittee's decision to implement the shutdown during the selected time period. [Consent Decree, R307-401]

II.B.8.a.1	The SO_2 emission factor for the FCC and Catalyst Regenerator shall be determined by continuous emission monitor. The regenerator flow rate calculation established in 40 CFR 63 Subpart UUU (MACT UUU) shall be used in conjunction for this calculation. For continuous emission monitor calculations, the monitor shall be operated, maintained, certified, and calibrated in accordance with R307-170, UAC. The provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to Continuous Opacity Monitoring Systems) and Part 60 Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60 Appendix B are applicable to the FCC/Catalyst Regenerator CEM. With respect to 40 C.F.R. Part 60, Appendix F, Chevron must conduct either a Relative Accuracy Audit ("RAA") or a Relative Accuracy Test Audit ("RATA") on each CEMS at least once every one year. The source must also conduct Cylinder Gas Audits ("CGA") each calendar quarter during which a RAA or a RATA is not performed. With respect to the O_2 CEMS, in lieu of the audit points specified in 40 C.F.R. Part 60, Appendix F § 5.1.2., the source may audit the O_2 CEMS at 20-30% and 50-60% of the actual O_2 CEMS span value. If a new monitor is installed, an initial performance evaluation shall be performed within 30 days of installation. The performance evaluation shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 60, Appendix B: Performance Specification 2. Notification must be made to the Director prior to conducting the performance test. Whenever the SO_2 CEM is bypassed for short periods, SO_2 CEM data from the previous three days will be averaged and used as an emission factor to determine emissions. For the stack test calculations to establish the FCC and Catalyst Regenerator SO_2 emission factor, the owner/operator shall determine mass emission rates (lbs/hr, etc.) as follows: The pollutant concentration, as determined by the appropriate methods, shall be multiplied by the volumetric flow rate and any necessary conversion factors as determined by the Director. The owner/operator shall maintain a record of fuel meter identifiers and locations, conversion factors, and other information required to demonstrate the required calculations. Records shall be kept showing the daily fuel usage, fuel meter readings, required fuel properties, hours of equipment operation, and calculated daily emissions. [R307-170]
II.B.8.b	Emissions of NO_x from the FCCU Regenerator Vent shall not exceed the following rates: A. 100 tons of NO_x per year on a rolling 12-month basis B. 0.55 tons per day C. 57.8 ppmvd @ 0% O_2 on a 365-day rolling average D. 106.3 ppmvd @ 0% O_2 on a 7-day rolling average The NO_x long-term limit listed in C. above shall apply at all times the FCCU is in operation. The NO_x short-term limit listed in D. above shall exclude periods of startup, shutdown, and malfunction. It shall also exclude FCCU feed hydrotreater outage if the owner/operator complies with an EPA-approved hydrotreater outage plan. It shall apply at all other times the FCCU is in operation. [R307-401]

II.B.8.b.1	The NO_x emission factor for the FCC and Catalyst Regenerator shall be determined by a continuous emission monitor. The regenerator flow rate calculation established in 40 CFR 63 Subpart UUU (MACT UUU) shall be used in conjunction for this calculation. For continuous emission monitor calculations, the monitor shall be operated, maintained, calibrated, and certified in accordance with R307-170, UAC, and the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to Continuous Opacity Monitoring Systems) and Part 60 Appendices A and F and the applicable performance specification test of 40 C.F.R. Part 60 Appendix B. With respect to 40 C.F.R. Part 60, Appendix F, Chevron must conduct either a Relative Accuracy Audit ("RAA") or a Relative Accuracy Test Audit ("RATA") on each CEMS at least once every one year. The source must also conduct Cylinder Gas Audits ("CGA") each calendar quarter during which a RAA or a RATA is not performed. With respect to the O_2 CEMS, in lieu of the audit points specified in 40 C.F.R. Part 60, Appendix F § 5.1.2., the source may audit the O_2 CEMS at 20-30% and 50-60% of the actual O_2 CEMS span value. If a new monitor is installed, an initial performance evaluation shall be performed within 30 days of installation. The performance evaluation shall be conducted and data reduced in accordance with the test methods and procedures contained in 40 CFR 60, Appendix B: Performance Specification 2. Notification must be made to the Director prior to conducting the performance test. Whenever the NO_x CEM is bypassed for short periods, NO_x CEM data from the previous three days will be averaged and used as an emission factor to determine emissions. For stack test calculations and mass emission rates (lbs/hr, etc.), the pollutant concentration, as determined by the appropriate methods, shall be multiplied by the volumetric flow rate and any necessary conversion factors as determined by the Director to establish the FCC and Catalyst Regenerator NO_x emission factor. The source shall maintain a record of fuel meter identifiers and locations, conversion factors, and other information required to demonstrate the required calculations. Records shall be kept showing the daily fuel usage, fuel meter readings, required fuel properties, hours of equipment operation, and calculated daily emissions. [R307-170]
II.B.8.c	Emissions of CO from the FCCU shall not exceed 500 ppmvd at 0% O_2 on a one-hour average basis. CO emissions during periods of startup, shutdown, or malfunction shall not be used when determining compliance with this emission limit, provided that during such periods, Chevron implements good air pollution control practices to minimize CO emissions. [R307-401-4(1)]
II.B.8.c.1	The source shall use CO and O_2 CEMS to monitor compliance with the CO emission limit for the FCCU and Catalyst Regenerator. The source shall install, certify, maintain, and operate the CEMS in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to Continuous Opacity Monitoring Systems) and Part 60 Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60 Appendix B. With respect to 40 C.F.R. Part 60, Appendix F, Chevron must conduct either a Relative Accuracy Audit ("RAA") or a Relative Accuracy Test Audit ("RATA") on each CEMS at least once every one year. The source must also conduct Cylinder Gas Audits ("CGA") each calendar quarter during which an RAA or a RATA is not performed. With respect to the O_2 CEMS, in lieu of the audit points specified in 40 C.F.R. Part 60, Appendix F § 5.1.2., the source may audit the O_2 CEMS at 20-30% and 50-60% of the actual O_2 CEMS span value. [R307-170]
II.B.8.d	The owner or operator of an FCCU shall comply with an emission limit of 1.0 pounds PM per 1000 pounds of coke burn-off, on a three-hour average basis. [40 CFR 60 Subpart J, SIP Section IX.H.11.g.i.B.I]
II.B.8.d.1	Compliance with this limit shall be determined by following the stack test protocol specified in 40 C.F.R. §60.106(b) to measure PM emissions on the FCCU. Each owner/operator shall conduct stack tests once every three years at each FCCU. [SIP Section IX.H.11.g.i.B.II]

II.B.8.d.2	The owner/operator shall follow the stack test protocol specified in 40 C.F.R. § 60.106(b)(2) to measure PM emissions on the FCCU. The owner/operator shall conduct annual stack tests at each FCCU. Upon demonstrating through at least three annual tests that the PM limits are not being exceeded, the owner/operator may request EPA approval to conduct tests less frequently than annually. The owner/operator received approval from EPA, dated February 25, 2026, to conduct testing less frequently than annually. The owner/operator must complete stack testing at the FCCU every three years so long as the test is no more than 36 months from the previous test. If results measured during a stack test are greater than 0.80 pounds PM per 1000 pounds coke burned, the owner/operator must return to annual testing and perform the next test no later than 12 months from the previous test in accordance with paragraph 23A of the NSR Consent Decree. After two consecutive annual test results less than or equal to 0.80 pounds PM per 1000 pounds of coke burned, the owner/operator may return to completing stack tests every three years so long as the test is no more than 36 months from the previous test. [Consent Decree]
II.B.8.e	Each owner or operator of an FCCU subject to NSPS Ja shall install, operate, and maintain a continuous parameter monitor system (CPMS) to measure and record operating parameters from the FCCU and control devices as per the requirements of 40 CFR 60.105a(b)(1). Each owner or operator of an FCCU not subject to NSPS Ja shall install, operate, and maintain a continuous opacity monitoring system to measure and record opacity from the FCCU as per the requirements of 40 CFR 63.1572(b) and comply with the opacity limitation as per the requirements of Table 7 to Subpart UUU of Part 63. [SIP Section IX.H.11.g.i.B.III]
II.B.8.f	Opacity from the FCCU and Catalyst Regenerator shall be monitored by a continuous opacity monitoring system ("COMS"). The source shall install, certify, calibrate, maintain, and operate the COMS in accordance with 40 C.F.R. §§ 60.11, 60.13, and Part 60 Appendix A, and the applicable performance specification test of 40 C.F.R. Part 60 Appendix B. [Consent Decree]
II.B.9	**Conditions on Miscellaneous Diesel-fired Equipment**
II.B.9.a	The owner/operator shall not operate each emergency engine, backup pump or fire engine on site for more than 100 hours per calendar year during non-emergency situations. There is no time limit on the use of the engines during emergencies. [40 CFR 63 Subpart ZZZZ, R307-401-8]
II.B.9.a.1	To determine compliance with the above annual total, the owner/operator shall calculate a new 12-month total by the 20th day of each month using data from the previous 12 months. Records documenting the operation of each emergency engine shall be kept in a log and shall include the following: A. The date the equipment was used. B. The duration of operation in hours. C. The reason for the equipment usage. [40 CFR 63 Subpart ZZZZ, R307-401-8]
II.B.9.a.2	To determine the duration of operation, the owner/operator shall install a non-resettable hour meter for each emergency engine. [R307-401-8, 40 CFR 63 Subpart ZZZZ]
II.B.9.b	The owner/operator shall only use diesel fuel (e.g., fuel oil #1, #2, or diesel fuel oil additives) as fuel in each emergency engine. [R307-401-8]
II.B.9.b.1	The owner/operator shall only combust diesel fuel that meets the definition of ultra-low sulfur diesel (ULSD), which has a sulfur content of 15 ppm or less. [R307-401-8]

II.B.9.b.2	To demonstrate compliance with the ULSD fuel requirement, the owner/operator shall maintain records of diesel fuel purchase invoices or obtain certification of sulfur content from the diesel fuel supplier. The diesel fuel purchase invoices shall indicate that the diesel fuel meets the ULSD requirements. [R307-401-8]
II.B.9.c	The following engines qualify under 40 CFR 63.6590(c), Stationary RICE subject to regulations under 40 CFR Part 60 Subpart IIII: A. North tank field generator: one backup generator. Engine Rating: 896 hp. Generator Rating: 600 kW. B. TCLR generator: backup generator. Engine Rating: 197 hp. Generator Rating: 125 kW. C. WWTP: One Backup Generator. Engine Rating: 896 hp. Generator Rating: 600 kW. D. One canal-fire water emergency generator. Engine Rating: 462 hp. Generator Rating: 300 kW. These engines must meet the requirements of 40 CFR 63 Subpart ZZZZ by meeting the requirements of 40 CFR 60 Subpart IIII. The requirements are listed at §60.4211(a), (c), (f), and (g). These engines are not subject to any additional requirements of 40 CFR 63 Subpart ZZZZ. [40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ]
II.B.10	**Conditions on Reformer Compressor Engines**
II.B.10.a	Emissions of NO_x and CO at the three listed reformer compressors shall not exceed the following concentration limits: K35001: 236 ppmvd NO_x, 834 ppmvd CO K35002: 208 ppmvd NO_x, 926 ppmvd CO K35003: 230 ppmvd NO_x, 556 ppmvd CO [R307-401-8(1)(a)]

II.B.10.a.1	Demonstrating Compliance with Emission Limits A. Beginning no later than one year after the Emission Limits Tests and every two years thereafter, the owner/operator shall perform emission tests to demonstrate compliance with the emission limits established for the reformer compressor engines. The tests shall be conducted on each engine and shall be the average of three one-hour tests on each engine. The tests shall be conducted, and the emissions shall be calculated, in accordance with 40 CFR § 60.4244. B. The owner/operator shall continuously measure and record the catalyst inlet temperature data according to 40 CFR § 63.6625(b); reduce these data to four-hour rolling averages, and maintain the four-hour rolling averages within the operating limitations for the catalyst inlet temperature, except for periods of startup, shutdown, and malfunction, as those terms are defined in 40 CFR § 60.2. C. The owner/operator shall measure and record the pressure drop across each catalyst bed once per month. The owner/operator shall maintain each catalyst bed so that the pressure drop across each catalyst is within the operating limitation established during the Emission Limits Tests. D. The owner/operator shall replace the O_2 sensor on each reformer compressor engine in accordance with the vendor-recommended preventative maintenance schedule. Following each O_2 sensor replacement, the owner/operator shall measure NO_x and CO emissions once using a portable analyzer to determine the adequate set point of the AFRC to maintain operation of the reformer compressor engine near stoichiometric conditions. The owner/operator shall maintain records documenting sensor replacement and portable analyzer results. [R307-150]
II.B.11	**Miscellaneous SIP Conditions**
II.B.11.a	The owner or operator shall comply with the requirements of 40 CFR 63.654 for heat exchange systems in VOC service. The owner or operator may elect to use another EPA-approved method other than the Modified El Paso Method if approved by the Director. The following applies in lieu of 40 CFR 63.654(b): A heat exchange system is exempt from the requirements in paragraphs 63.654(c) through (g) of this section if it meets any one of the criteria in the following paragraphs (1) through (2) of this section. 1. All heat exchangers that are in VOC service within the heat exchange system that either: a. Operate with the minimum pressure on the cooling water side at least 35 kilopascals greater than the maximum pressure on the process side; or b. Employ an intervening cooling fluid, containing less than 10 percent by weight of VOCs, between the process and the cooling water. This intervening fluid must serve to isolate the cooling water from the process fluid and must not be sent through a cooling tower or discharged. For purposes of this section, discharge does not include emptying for maintenance purposes. 2. The heat exchange system cools process fluids that contain less than 10 percent by weight VOCs (i.e., the heat exchange system does not contain any heat exchangers that are in VOC service). [SIP Section IX.H.11.g.iii.A]

II.B.11.b	For leak detection and repair, the owner/operator shall comply with the following: A. The owner/operator shall comply with the requirements of 40 CFR 60.590a to 60.593a. B. For units complying with the Sustainable Skip Period, previous process unit monitoring results may be used to determine the initial skip period interval provided that each valve has been monitored using the 500 ppm leak definition. [SIP Section IX.H.11.g.iv]
II.B.11.c	The owner/operator shall not allow any stationary tank of 40,000-gallon or greater capacity and containing or last containing any organic liquid with a true vapor pressure equal or greater than 10.5 kPa (1.52 psia) at storage temperature (see R307-324-4(1)) to be opened to the atmosphere unless the emissions are controlled by exhausting VOCs contained in the tank vapor space to a vapor control device until the organic vapor concentration is 10 percent or less of the lower explosion limit (LEL). These degassing provisions shall not apply while connecting or disconnecting degassing equipment. [SIP Section IX.H.11.g.vi]
II.B.11.c.1	The Director shall be notified of the intent to degas any tank subject to the rule. Except in an emergency situation, initial notification shall be submitted at least three days prior to degassing operations. The initial notification shall include: A. Start date and time; B. Tank owner, address, tank location, and applicable tank permit numbers; C. Degassing operator's name, contact person, and telephone number; D. Tank capacity, volume of space to be degassed, and materials stored; E. Description of vapor control device. [SIP Section IX.H.11.g.vi.C]
II.B.11.d	All hydrocarbon flares at petroleum refineries located in or affecting a $PM_{2.5}$ nonattainment or maintenance area or any PM_{10} nonattainment or maintenance area shall be subject to the flaring requirements of NSPS Subpart Ja (40 CFR 60.100a-109a), if not already subject under the flare applicability provisions of Ja. [SIP Section IX.H.11.g.v.A]
II.B.11.d.1	The owner/operator shall either: A. Install and operate a flare gas recovery system designed to limit hydrocarbon flaring produced from each affected flare during normal operations to levels below the values listed in 40 CFR 60.103a(c), or B. Limit flaring during normal operations to 500,000 scfd for each affected flare. Flare gas recovery is not required for dedicated SRU flare and header systems, or HF flare and header systems. [SIP Section IX.H.11.g.v.B]

PERMIT HISTORY

This Approval Order shall supersede (if a modification) or will be based on the following documents:

Supersedes	AO DAQE-AN101190107-24 dated December 3, 2024
Is Derived From	NOI dated September 11, 2025
Incorporates	Additional Information Received dated March 5, 2026

ACRONYMS

The following lists commonly used acronyms and associated translations as they apply to this document:

40 CFR	Title 40 of the Code of Federal Regulations
AO	Approval Order
BACT	Best Available Control Technology
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CDS	Classification Data System (used by Environmental Protection Agency to classify sources by size/type)
CEM	Continuous emissions monitor
CEMS	Continuous emissions monitoring system
CFR	Code of Federal Regulations
CMS	Continuous monitoring system
CO	Carbon monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent - Title 40 of the Code of Federal Regulations Part 98, Subpart A, Table A-1
COM	Continuous opacity monitor
DAQ/UDAQ	Division of Air Quality
DAQE	This is a document tracking code for internal Division of Air Quality use
EPA	Environmental Protection Agency
FDCP	Fugitive dust control plan
GHG	Greenhouse Gas(es) - Title 40 of the Code of Federal Regulations 52.21 (b)(49)(i)
GWP	Global Warming Potential - Title 40 of the Code of Federal Regulations Part 86.1818-12(a)
HAP or HAPs	Hazardous air pollutant(s)
ITA	Intent to Approve
LB/YR	Pounds per year
MACT	Maximum Achievable Control Technology
MMBTU	Million British Thermal Units
NAA	Nonattainment Area
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOI	Notice of Intent
NO_x	Oxides of nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
PM_{10}	Particulate matter less than 10 microns in size
$PM_{2.5}$	Particulate matter less than 2.5 microns in size
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
R307	Rules Series 307
R307-401	Rules Series 307 - Section 401
SO_2	Sulfur dioxide
Title IV	Title IV of the Clean Air Act
Title V	Title V of the Clean Air Act
TPY	Tons per year
UAC	Utah Administrative Code
VOC	Volatile organic compounds