



State of Utah

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Department of
Environmental Quality

Kimberly D. Shelley
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQE-IN101190101-21

June 9, 2021

Serena Yau
Chevron Products Co - SL Refinery
685 S Chevron Way
North Salt Lake, UT 84054
LVanderWerff@chevron.com

Dear Ms. Yau:

Re: Intent to Approve:
Modification of DAQE-AN101190099-20 to Add One (1) Diesel Generator and Incorporate
Conditions of Consent Decree No. C 03-04650
Project Number: N101190101

The attached document is the Intent to Approve (ITA) for the above-referenced project. The ITA is subject to public review. Any comments received shall be considered before an Approval Order (AO) is issued. The Division of Air Quality is authorized to charge a fee for reimbursement of the actual costs incurred in the issuance of an AO. An invoice will follow upon issuance of the final AO.

Future correspondence on this ITA should include the engineer's name, **John Jenks**, as well as the DAQE number as shown on the upper right-hand corner of this letter. John Jenks, can be reached at (385) 306-6510 or jjenks@utah.gov, if you have any questions.

Sincerely,

Joe Thomas (Jun 9, 2021 10:41 MDT)

Joe Thomas, Branch Manager
New Source Review Section

JLB:JJ:sb

cc: Salt Lake Valley Health Department
Dan Fagnant, EPA Region 8

STATE OF UTAH

**Department of Environmental Quality
Division of Air Quality**

**INTENT TO APPROVE
DAQE-IN101190101-21**

**Modification of DAQE-AN101190099-20 to Add One Diesel
Generator and Incorporate Conditions of Consent Decree No. C 03-
04650**

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

**Issued to
Chevron Products Co - SL Refinery- Salt Lake Refinery**

**Issued On
June 9, 2021**



Joe Thomas (Jun 9, 2021 10:41 MDT)

**Joe Thomas
Branch Manager NSR**

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GENERAL INFORMATION

CONTACT/LOCATION INFORMATION

Owner Name

Chevron Products Co - SL Refinery

Source Name

Chevron Products Co - SL Refinery- Salt Lake Refinery

Mailing Address685 South Chevron Way
North Salt Lake, UT 84054**Physical Address**685 South Chevron Way
North Salt Lake, UT 84054**Source Contact**Name Lauren Vander Werff
Phone (801) 539-7386
Email LVanderWerff@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

The Chevron Refinery is a petroleum refinery with a nominal capacity of approximately 50,000 barrels per day of crude oil. The source consists of one (1) fluidized catalytic cracking unit (FCCU), a delayed coking unit, a catalytic reforming unit, hydrotreating units and two (2) 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

Minor Modification at Major Source

Source ClassificationLocated in, Northern Wasatch Front O3 NAA, Salt Lake City UT PM_{2.5} NAA
Davis County
Airs Source Size: AApplicable 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), 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

NSPS (Part 60), GGG: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006

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

NESHAP (Part 61), A: General Provisions

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
Title V (Part 70) Major Source

Project Description

Chevron Products Company (Chevron) is required to comply with the terms of Consent Decree (CD) No. C 03-04650. One provision of that decree is to submit an application (NOI) and take all other reasonable actions necessary to obtain all such state or local permits or approvals (AOs) as may be necessary. The NOI was submitted on June 8, 2020. The document also included additional information on a diesel-fired generator to be installed at the Reformer substation. In addition, Chevron and UDAQ are taking this opportunity to update the naming convention of the listed emergency generators to add clarity.

As the requirements of the CD have already been through public comment, only those conditions associated with the new diesel generator are subject to public notice and comment under R307-401-7. The changes associated with the CD include: Inclusion of sulfur pit limitations, clarification of SO₂ emission limits, and listing federal requirements on CEMs and COMs.

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)
CO2 Equivalent	31.0	988808.60
Carbon Monoxide	0.03	991.16
Nitrogen Oxides	0.00	766.50
Particulate Matter - PM10	0.00	260.98
Particulate Matter - PM2.5	0.00	110.00
Sulfur Dioxide	0.00	383.30
Volatile Organic Compounds	0.07	1242.09

Hazardous Air Pollutant	Change (lbs/yr)	Change (TPY)
Benzene	0.35	1.75E-04
Toluene	0.15	7.67E-05
Xylenes	0.11	5.35E-05
1,3-Butadiene	0.01	7.34E-06
Formaldehyde	0.44	2.21E-04
Acetaldehyde	0.29	1.44E-04
Acrolein	0.03	1.74E-05
Naphthalene	0.03	1.59E-05
Acenaphthylene	0.00	9.49E-07
Acenaphthene	0.00	2.66E-07
Fluorene	0.01	5.48E-06
Phenanthrene	0.01	5.52E-06
Anthracene	0.00	3.51E-07
Fluoranthene	0.00	1.43E-06
Pyrene	0.00	8.97E-07
Benz(a)anthracene	0.00	3.15E-07
Chrysene	0.00	6.62E-08
Benzo(b)fluoranthene	0.00	1.86E-08
Benzo(k)fluoranthene	0.00	2.91E-08
Benzo(a)pyrene	0.00	3.53E-08
Indeno(1,2,3-cd)pyrene	0.00	7.04E-08
Dibenz(a,h)anthracene	0.00	1.09E-07
Benzo(g,h,l)perylene	0.00	9.17E-08
	Change (lbs/yr)	Change (TPY)
Total HAPs	1.45	7.27E-04

PUBLIC NOTICE STATEMENT

The NOI for the above-referenced project has been evaluated and has been found to be consistent with the requirements of UAC R307. Air pollution producing sources and/or their air control facilities may not be constructed, installed, established, or modified prior to the issuance of an AO by the Director.

A 30-day public comment period will be held in accordance with UAC R307-401-7. A notification of the intent to approve will be published in the Salt Lake Tribune on June 13, 2021. During the public comment period the proposal and the evaluation of its impact on air quality will be available for the public to review and provide comment. If anyone so requests a public hearing within 15 days of publication, it will be held in accordance with UAC R307-401-7. The hearing will be held as close as practicable to the location of the source. Any comments received during the public comment period and the hearing will be evaluated. The proposed conditions of the AO may be changed as a result of the comments received.

SECTION I: GENERAL PROVISIONS

The intent is to issue an air quality AO authorizing the project with the following recommended conditions and that failure to comply with any of the conditions may constitute a violation of the AO.

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 (5) 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]

I.8	The owner/operator shall submit documentation of the status of construction or modification of the new emergency engines listed in II.A.34 (the canal fire water system) to the Director within 18 months from the date of this AO. This AO may become invalid if construction is not commenced within 18 months from the date of this AO or if construction is discontinued for 18 months or more. To ensure proper credit when notifying the Director, send the documentation to the Director, attn.: NSR Section. [R307-401-18]
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SECTION II: PERMITTED EQUIPMENT

The intent is to issue an air quality AO authorizing the project with the following recommended conditions and that failure to comply with any of the conditions may constitute a violation of the AO.

II.A THE APPROVED EQUIPMENT

II.A.1	Main Refinery Chevron Salt Lake Refinery
II.A.2	F-11005 Boiler #11005 (Boiler #5, Low-NO _x), 171 MMBtu/hr
II.A.3	F-11006 Boiler #11006 (Boiler #6, Low-NO _x), 171 MMBtu/hr
II.A.4	F-11007 Boiler #11007 (Boiler #7, Low-NO _x and FGR), 225 MMBtu/hr
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 (Low-NO _x), 130 MMBtu/hr
II.A.10	F-21002 Crude Unit Furnace #F-21002 (Low-NO _x), 115.1 MMBtu/hr
II.A.11	F-32021 FCC Furnace F-32021, 48.2 MMBtu/hr
II.A.12	F-32023 FCC Furnace F-32023, 48.2 MMBtu/hr
II.A.13	F-71010 HDN Furnace F-71010, 15.6 MMBtu/hr

II.A.14	F-71030 HDN Furnace F-71030, 36.3 MMBtu/hr
II.A.15	F-35001 Reformer Furnace F-35001, 52.3 MMBtu/hr
II.A.16	F-35002 Reformer Furnace F-35002, 45 MMBtu/hr
II.A.17	F-35003 Reformer Furnace F-35003, 31.7 MMBtu/hr
II.A.18	Alkylation Unit Includes: Alkylation Furnace F-36017 (Low-NO _x), 108 MMBtu/hr
II.A.19	F-70001 Coker Furnace F-70001, 139.2 MMBtu/hr
II.A.20	F-64010 HDS Furnace F-64010 (Low-NO _x), 19 MMBtu/hr
II.A.21	F-64011 HDS Furnace F-64011 (Low-NO _x), 27.3 MMBtu/hr
II.A.22	F-66100 VGO Furnace F-66100 (Low-NO _x), 40 MMBtu/hr
II.A.23	F-66200 VGO Furnace F-66200 (Low-NO _x), 66 MMBtu/hr
II.A.24	SRU/TGTU/TGI #1 SRU and Tail Gas Incinerator #1
II.A.25	SRU/TGTU/TGI #2 SRU and Tail Gas Incinerator #2
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	<p>Diesel-powered back-up equipment: 2nd north substation generator: one(1) emergency generator rated at 670 hp (500 kW) #1 CWT cooling pump: one (1) emergency cooling water pump rated at 630 hp (470 kW) HDN substation generator: one (1) emergency generator rated at 536 hp (400 kW) two (2) fire water emergency backup pumps rated at 375 hp (cont)/400 hp (max) each VGO generator: one (1) backup generator rated at 680 hp (prime) 755 hp (standby)</p>
II.A.32	<p>Diesel-powered back-up equipment (cont.) Two (2) HF mitigation pumps rated at 830 hp (619 kW) each Crude substation generator: one (1) backup generator rated at 820 hp (611 kW) 3rd north substation generator: one (1) backup emergency generator rated at 1490 hp (1111 kW) Admin building generator: one (1) backup generator rated at 1676 hp (1250 kW) TCLR Generator & WWTP generator: two (2) backup generators rated at 168 hp (125 kW) North tank field generator: one (1) backup generator rated at 422 hp (315 kW)</p>
II.A.33	<p>Diesel-powered back-up equipment (cont.) Alky emergency generator: one (1) emergency generator rated at 670 hp (500 kW) Boiler plant compressors: two (2) compressors rated at 524 hp (391 kW) each Collection box backup pump: one (1) pump rated at 109 hp (81.4 kW) FCC MCC generator: one (1) emergency generator rated at 805 hp (601 kW) three (3) fire water pumps rated at 755 hp (563.5 kW) each one (1) canal fire water emergency generator rated at 369 hp (275 kW)</p>
II.A.34	<p>Diesel-powered back-up equipment (new) Reformer substation generator: one (1) emergency generator at 400 kW</p>
II.A.35	<p>Natural gas-powered backup equipment One (1) emergency generator rated at 50 hp</p>
II.A.36	<p>K35001, K35002, K35003 Three (3) Reformer Compressor Drivers (refinery fuel gas-fired), 16 MMBtu/hr each</p>
II.A.37	<p>Amine Unit #1 Amine Unit #1</p>
II.A.38	<p>Amine Unit #2 Amine Unit #2</p>
II.A.39	<p>K36067 Lime Loading Facility K36067</p>
II.A.40	<p>FCC Fines Bin</p>

SECTION II: SPECIAL PROVISIONS

The intent is to issue an air quality AO authorizing the project with the following recommended conditions and that failure to comply with any of the conditions may constitute a violation of the AO.

II.B REQUIREMENTS AND LIMITATIONS

II.B.1	Conditions on permitted source (source-wide)
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 ₂ S 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 80.510 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]

<p>II.B.1.e</p>	<p>The owner/operator shall ensure for all stack testing performed:</p> <p>The owner/operator shall provide a pre-test protocol at least 45 days prior to the test. A pretest conference between the owner/operator, the tester, and the Director shall be held at least 30 days prior to the test 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 (3) 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.</p> <p>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:</p> <p>Volumetric flow rate - 40 CFR 60, Appendix A, Method 2</p> <p>SO₂ emissions - 40 CFR 60, Appendix A, Method 6C</p> <p>NO_x emissions - 40 CFR 60, Appendix A, Method 7E</p> <p>PM₁₀ and PM_{2.5} emissions - 40 CFR 51, Appendix M, Methods 201a and 202</p> <p>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.</p> <p>[R307-401]</p>
<p>II.B.1.f</p>	<p>Source-wide combined emissions of PM₁₀ shall not exceed 0.715 tons per day (tpd). [SIP Section IX.H.2.d.i]</p>

<p>II.B.1.f.1</p>	<p>Compliance with the source-wide PM₁₀ Cap shall be determined for each day as follows:</p> <ul style="list-style-type: none"> A. Total 24-hour PM₁₀ emissions for the emission points shall be calculated by adding the daily results of the PM₁₀ 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 PM₁₀ 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. <p>[SIP Section IX.H.2.d.i.C]</p>
<p>II.B.1.f.2</p>	<p>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:</p> <ul style="list-style-type: none"> A. Natural gas: Filterable PM₁₀: 1.9 lb/MMscf Condensable PM₁₀: 5.7 lb/MMscf B. Plant gas: Filterable PM₁₀: 1.9 lb/MMscf Condensable PM₁₀: 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 PM₁₀ 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. <p>[SIP Section IX.H.2.d.i.A]</p>

<p>II.B.1.f.3</p>	<p>The default emission factors listed above apply until such time as stack testing is conducted.</p> <p>Initial PM₁₀ stack testing on the FCC stack has been performed and shall be conducted at least once every three (3) years from the date of the last stack test.</p> <p>Stack testing shall be performed as outlined in Condition II.B.1.e.</p> <p>[SIP Section IX.H.2.d.i.B]</p>
<p>II.B.1.g</p>	<p>Source-wide combined emissions of PM_{2.5} (filterable+condensable) shall not exceed 0.305 tons per day (tpd) and 110 tons per rolling 12-month period. [SIP Section IX.H.12.d.i]</p>
<p>II.B.1.g.1</p>	<p>Compliance with the source-wide PM_{2.5} Cap shall be determined for each day as follows:</p> <p>A. Total 24-hour PM_{2.5} emissions for the emission points shall be calculated by adding the daily results of the PM_{2.5} emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the FCCU to arrive at a combined daily PM_{2.5} emission total.</p> <p>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.</p> <p>C. Daily natural gas and plant gas consumption shall be determined through the use of flow meters.</p> <p>D. Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.</p> <p>E. The equation used to determine emissions for the boilers and furnaces shall be as follows:</p> <p>Emissions = Emission Factor (lb/MMscf) * Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton)</p> <p>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.</p> <p>[SIP Section IX.H.12.d.i.C]</p>

<p>II.B.1.g.2</p>	<p>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:</p> <ul style="list-style-type: none"> A. Natural gas: Filterable PM_{2.5}: 1.9 lb/MMscf Condensable PM_{2.5}: 5.7 lb/MMscf B. Plant gas: Filterable PM_{2.5}: 1.9 lb/MMscf Condensable PM_{2.5}: 5.7 lb/MMscf C. Diesel fuel: shall be determined from the latest edition of AP-42 or other EPA approved methods. D. FCC Stack: The PM_{2.5} emission factors shall be based on the most recent stack test and verified by parametric monitoring. E. Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel. <p>[SIP Section IX.H.12.d.i.A]</p>
<p>II.B.1.g.3</p>	<p>The default emission factors listed above apply until such time as stack testing is conducted.</p> <p>Initial PM_{2.5} stack testing on the FCC stack has been performed and shall be conducted at least once every three (3) years from the date of the last stack test.</p> <p>Stack testing shall be performed as outlined in Condition II.B.1.e.</p> <p>[SIP Section IX.H.12.d.i.B]</p>
<p>II.B.1.h</p>	<p>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.12.d.ii]</p>

<p>II.B.1.h.1</p>	<p>Compliance with the source-wide NO_x Cap shall be determined for each day as follows:</p> <ul style="list-style-type: none"> 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. <p>[SIP Section IX.H.12.d.ii.C]</p>
<p>II.B.1.h.2</p>	<p>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:</p> <ul style="list-style-type: none"> 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. Alkylation polymer: shall be determined from the latest edition of AP-42 (as fuel oil #6) or other EPA approved methods. D. Diesel fuel: shall be determined from the latest edition of AP-42 or other EPA approved methods. E. Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel. <p>[SIP Section IX.H.12.d.ii.A]</p>
<p>II.B.1.h.3</p>	<p>The default emission factors listed above apply until such time as stack testing is conducted.</p> <p>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 (3) 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.</p> <p>Stack testing shall be performed as outlined in Condition II.B.1.e.</p> <p>[SIP Section IX.H.12.d.ii.B]</p>

II.B.1.i	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.12.d.iii]
II.B.1.i.1	<p>Compliance with the source-wide SO₂ Cap shall be determined for each day as follows:</p> <ul style="list-style-type: none"> A. Total daily SO₂ emissions shall be calculated by adding the daily SO₂ 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 H₂S (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. <p>[SIP Section IX.H.12.d.iii.B]</p>
II.B.1.i.2	<p>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:</p> <ul style="list-style-type: none"> A. FCCU: The emission rate shall be determined by the FCC SO₂ 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: $EF \text{ (lb SO}_2\text{/k gal)} = \text{density (lb/gal)} * (1000 \text{ gal/k gal)} * \text{wt.\% S}/100 * (64 \text{ lb SO}_2\text{/32 lb S)}$ E. Plant gas: the emission factor shall be calculated from the H₂S measurement obtained from the H₂S CEM. F. Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel. <p>[SIP Section IX.H.12.d.iii.A]</p>

II.B.2	Conditions on Boiler #11005 (Boiler #5)
II.B.2.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)] $En = ((0.1 \times Hgo) + (0.2 \times Hr)) / (Hgo + Hr)$ <p>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.</p> [40 CFR 60 Subpart Db]
II.B.2.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 (3) years through testing as outlined in Condition II.B.1.e. [40 CFR 60 Subpart Db]
II.B.3	Conditions on Boiler #11006 (Boiler #6)
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)] $En = ((0.1 \times Hgo) + (0.2 \times Hr)) / (Hgo + Hr)$ <p>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.</p> [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 (3) years through testing as outlined in Condition II.B.1.e. [40 CFR 60 Subpart Db]
II.B.4	Conditions on the SRUs
II.B.4.a	All petroleum refineries in or affecting any PM _{2.5} nonattainment 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.4.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.4.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.5	Conditions on SRU and Tail Gas Treatment Unit #1
II.B.5.a	Emissions of SO ₂ from SRU #1 shall not exceed 0.242 tons/day. [R307-401]

<p>II.B.5.a.1</p>	<p>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.</p> <p>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 SO₂ CEM is bypassed for short periods, SO₂ CEM data from the previous three days will be averaged and used as an emission factor to determine emissions.</p> <p>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 SO₂ concentration, the mass flow rate, and the resulting calculated emissions. Records of all CEM calibrations shall also be maintained.</p> <p>[R307-401]</p>
<p>II.B.5.b</p>	<p>Emissions of SO₂ from SRU #1 shall not exceed 88.5 tons/yr. [R307-401]</p>
<p>II.B.5.b.1</p>	<p>Compliance shall be determined on a 12-month rolling average. Each month, the SO₂ 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]</p>
<p>II.B.5.c</p>	<p>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]</p>
<p>II.B.6</p>	<p>Conditions on SRU and Tail Gas Treatment Unit #2</p>
<p>II.B.6.a</p>	<p>Emissions of SO₂ from SRU #2 shall not exceed 0.268 tons/day. [R307-401]</p>

<p>II.B.6.a.1</p>	<p>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.</p> <p>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 SO₂ CEM is bypassed for short periods, SO₂ CEM data from the previous three days will be averaged and used as an emission factor to determine emissions.</p> <p>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 SO₂ concentration, the mass flow rate, and the resulting calculated emissions. Records of all CEM calibrations shall also be maintained.</p> <p>[R307-401]</p>
<p>II.B.6.b</p>	<p>Emissions of SO₂ from SRU #2 shall not exceed 97.7 tons/yr. [R307-401]</p>
<p>II.B.6.b.1</p>	<p>Compliance shall be determined on a 12-month rolling average. Each month, the SO₂ 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]</p>
<p>II.B.6.c</p>	<p>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]</p>

<p>II.B.7</p>	<p>Conditions on the FCC and Catalyst Regenerator</p>
<p>II.B.7.a</p>	<p>Emissions of SO₂ from the FCCU Regenerator Vent shall not exceed the following rates and concentrations:</p> <ul style="list-style-type: none"> A. 25 ppmvd SO₂ @ 0% O₂ on a 365-day rolling average B. 50 ppmvd SO₂ @ 0% O₂ on a 7-day rolling average C. 50 tons of SO₂ on a 12-month rolling average D. 0.28 tons of SO₂ per day. <p>SO₂ emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the emission limit of 50 ppmvd SO₂ @ 0% O₂ on a 7-day rolling average basis.</p> <p>The SO₂ 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.</p> <p>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.</p> <p>[Consent Decree, R307-401]</p>

<p>II.B.7.a.1</p>	<p>The SO₂ 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.</p> <p>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 (1) 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 O₂ 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 O₂ CEMS at 20-30% and 50-60% of the actual O₂ 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 SO₂ CEM is bypassed for short periods, SO₂ CEM data from the previous three days will be averaged and used as an emission factor to determine emissions.</p> <p>For the stack test calculations to establish the FCC and Catalyst Regenerator SO₂ emission factor, the owner/operator shall determine mass emission rates (lbs/hr, etc.) as follows:</p> <p>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.</p> <p>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.</p> <p>[R307-170]</p>
<p>II.B.7.b</p>	<p>Emissions of NO_x from the FCCU Regenerator Vent shall not exceed the following rates:</p> <ul style="list-style-type: none"> 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% O₂ on a 365-day rolling average D. 106.3 ppmvd @ 0% O₂ on a 7-day rolling average <p>The NO_x long-term limit listed in C. above shall apply at all times the FCCU is in operation.</p> <p>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.</p> <p>[R307-401]</p>

II.B.7.b.1	<p>The NO_x 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.</p> <p>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 (1) 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 O₂ 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 O₂ CEMS at 20-30% and 50-60% of the actual O₂ 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.</p> <p>For stack test calculations, 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.</p> <p>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.</p> <p>[R307-170]</p>
II.B.7.c	<p>Emissions of CO from the FCCU shall not exceed 500 ppmvd at 0% O₂ on a 1-hour average basis. CO emissions during periods of startup, shutdown or malfunction shall not be used when determining compliance with this emission limit. [R307-401-8]</p>
II.B.7.c.1	<p>The source shall use CO and O₂ 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 (1) 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 O₂ 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 O₂ CEMS at 20-30% and 50-60% of the actual O₂ CEMS span value. [R307-170]</p>
II.B.7.d	<p>The owner or operator of an FCCU shall comply with an emission limit of 1.0 pounds PM per 1000 pounds coke burn-off. [SIP Section IX.H.11.g.i.B.I]</p>
II.B.7.d.1	<p>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 (3) years at each FCCU. [SIP Section IX.H.11.g.i.B.II]</p>

II.B.7.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.7.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.8	Conditions on Miscellaneous Diesel-fired Equipment
II.B.8.a	The owner/operator shall not operate each emergency engine, back-up 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 60 Subpart ZZZZ, R307-401-8]
II.B.8.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 60 Subpart ZZZZ, R307-401-8]
II.B.8.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.8.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.8.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.8.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]

<p>II.B.8.c</p>	<p>The following engines qualify under 40 CFR 63.6590(c) Stationary RICE subject to Regulations under 40 CFR Part 60:</p> <ol style="list-style-type: none"> 1. North tank field generator: one (1) backup generator rated at 422 hp (315 kW) 2. Two (2) fire water emergency backup pumps rated at 375 hp (cont)/400 hp (max) each 3. TCLR generator: backup generator rated at 168 hp (125 kW) 4. Collection box backup pump: one (1) pump rated at 109 hp (81.4 kW) 5. One (1) canal fire water emergency generator rated at 369 hp (275 kW) <p>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.</p> <p>[40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ]</p>
<p>II.B.9</p>	<p>Conditions on Reformer Compressor Engines</p>
<p>II.B.9.a</p>	<p>Emissions of NO_x and CO at the three listed reformer compressors shall not exceed the following concentration limits:</p> <p>K35001: 236 ppmvd NO_x, 834 ppmvd CO K35002: 208 ppmvd NO_x, 926 ppmvd CO K35003: 230 ppmvd NO_x, 556 ppmvd CO.</p> <p>[R307-401-8(1)(a)]</p>

<p>II.B.9.a.1</p>	<p>Demonstrating Compliance with Emission Limits</p> <p>A. Beginning no later than one (1) year after the Emission Limits Tests and every two (2) 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 (3) one-hour tests on each engine. The tests shall be conducted, and the emissions shall be calculated, in accordance with 40 CFR § 60.4244.</p> <p>B. The owner/operator shall continuously measure and record the catalyst inlet temperature data in according to 40 CFR § 63.6625(b); reduce these data to 4-hour rolling averages, and maintain the 4-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.</p> <p>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.</p> <p>D. The owner/operator shall replace the O₂ sensor on each reformer compressor engine in accordance with the vendor-recommended preventative maintenance schedule. Following each O₂ 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.</p> <p>[R307-150]</p>
<p>II.B.10</p>	<p>Miscellaneous SIP Conditions</p>
<p>II.B.10.a</p>	<p>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.</p> <p>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.</p> <p>1. All heat exchangers that are in VOC service within the heat exchange system that either:</p> <p>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</p> <p>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.</p> <p>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).</p> <p>[SIP Section IX.H.11.g.iii.A]</p>

<p>II.B.10.b</p>	<p>For leak detection and repair, the owner/operator shall comply with the following:</p> <ul style="list-style-type: none"> 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. <p>[SIP Section IX.H.11.g.iv]</p>
<p>II.B.10.c</p>	<p>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).</p> <p>These degassing provisions shall not apply while connecting or disconnecting degassing equipment.</p> <p>[SIP Section IX.H.11.g.vi]</p>
<p>II.B.10.c.1</p>	<p>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 (3) days prior to degassing operations. The initial notification shall include:</p> <ul style="list-style-type: none"> 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. <p>[SIP Section IX.H.11.g.vi.C]</p>
<p>II.B.10.d</p>	<p>All hydrocarbon flares at petroleum refineries located in or affecting a PM_{2.5} nonattainment area or any PM₁₀ 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]</p>
<p>II.B.10.d.1</p>	<p>The owner/operator shall either:</p> <ul style="list-style-type: none"> 1. 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 2) limit flaring during normal operations to 500,000 scfd for each affected flare. <p>Flare gas recovery is not required for dedicated SRU flare and header systems, or HF flare and header systems.</p> <p>[SIP Section IX.H.11.g.v.B]</p>

PERMIT HISTORY

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

Is Derived From
Incorporates
Supersedes

Source Submitted NOI dated June 8, 2020
Additional Information Received dated June 8, 2020
DAQE-AN101190099-20 dated August 26, 2020

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