

Utah State Implementation Plan

Emission Limits and Operating Practices

Section IX, Part H

DRAFT

Adopted by the Air Quality Board
, 2019

1 **H.1 General Requirements: Control Measures for Area and Point**
2 **Sources, Emission Limits and Operating Practices, PM₁₀ Requirements**
3

- 4 a. Except as otherwise outlined in individual conditions of this Subsection IX.H.1 listed
5 below, the terms and conditions of this Subsection IX.H.1 shall apply to all sources
6 subsequently addressed in Subsection IX.H.2 and IX.H.3. Should any inconsistencies
7 exist between these two subsections, the source specific conditions listed in IX.H.2 and
8 IX.H.3 shall take precedence.
9
- 10 b. Definitions.
- 11 i. The definitions contained in R307-101-2, Definitions, apply to Section IX, Part H.
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- 13 ii. Natural gas curtailment means a period of time during which the supply of natural gas
14 to an affected facility is halted for reasons beyond the control of the facility. The act of
15 entering into a contractual agreement with a supplier of natural gas established for
16 curtailment purposes does not constitute a reason that is under the control of a facility
17 for the purposes of this definition. An increase in the cost or unit price of natural gas
18 does not constitute a period of natural gas curtailment.
19
- 20 c. Recordkeeping and Reporting
- 21
- 22 i. Any information used to determine compliance shall be recorded for all periods when
23 the source is in operation, and such records shall be kept for a minimum of five years.
24 Any or all of these records shall be made available to the Director upon request, and
25 shall include a period of two years ending with the date of the request.
26
- 27 ii. Each source shall comply with all applicable sections of R307-150 Emission
28 Inventories.
29
- 30 iii. Each source shall submit a report of any deviation from the applicable requirements of
31 this Subsection IX.H, including those attributable to upset conditions, the probable
32 cause of such deviations, and any corrective actions or preventive measures taken. The
33 report shall be submitted to the Director no later than 24-months following the
34 deviation or earlier if specified by an underlying applicable requirement. Deviations
35 due to breakdowns shall be reported according to the breakdown provisions of R307-
36 107.
37
- 38 d. Emission Limitations.
- 39
- 40 i. All emission limitations listed in Subsections IX.H.2 and IX.H.3 apply at all times,
41 unless otherwise specified in the source specific conditions listed in IX.H.2 and
42 IX.H.3.
43
- 44 ii. All emission limitations of PM₁₀ listed in Subsections IX.H.2 and IX.H.3 include both
45 filterable and condensable PM, unless otherwise specified in the source specific
46 conditions listed in IX.H.2 and IX.H.3.
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- 48 e. Stack Testing.

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- i. As applicable, stack testing to show compliance with the emission limitations for the sources in Subsection IX.H.2 and I.X.H.3 shall be performed in accordance with the following:
 - A. Sample Location: The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other EPA-approved testing methods acceptable to the Director. Occupational Safety and Health Administration (OSHA) approvable access shall be provided to the test location.
 - B. Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2, EPA Test Method No. 19 “SO₂ Removal & PM, SO₂ NO_x Rates from Electric Utility Steam Generators”, or other EPA-approved testing methods acceptable to the Director.
 - C. PM: 40 CFR 60, Appendix A Method 5, or other EPA-approved testing methods acceptable to the Director.
 - D. PM₁₀: 40 CFR 51, Appendix M, Methods 201a and 202, or other EPA approved testing methods acceptable to the Director. If a method other than 201a is used, the portion of the front half of the catch considered PM₁₀ shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.
 - E. SO₂: 40 CFR 60 Appendix A, Method 6C or other EPA-approved testing methods acceptable to the Director.
 - F. NO_x: 40 CFR 60 Appendix A, Method 7E or other EPA-approved testing methods acceptable to the Director.
 - G. Calculations: To determine mass emission rates (lb/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 to give the results in the specified units of the emission limitation.
 - H. A stack test protocol shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by the Director.
 - I. The production rate during all compliance testing shall be no less than 90% of the maximum production rate achieved in the previous three (3) years. If the desired production rate is not achieved at the time of the test, the maximum production rate shall be 110% of the tested achieved rate, but not more than the maximum allowable production rate. This new allowable maximum production rate shall remain in effect until successfully tested at a higher rate. The owner/operator shall request a higher production rate when necessary. Testing at no less than 90% of the higher rate shall be conducted. A new maximum production rate (110% of the new rate) will then be allowed if the test is successful. This process may be repeated until the maximum allowable production rate is achieved.
- f. Continuous Emission and Opacity Monitoring.

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- i. For all continuous monitoring devices, the following shall apply:
 - A. Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of unaffected source shall continuously operate all required continuous monitoring systems and shall meet minimum frequency of operation requirements as outlined in R307-170 and 40 CFR 60.13. Flow measurement shall be in accordance with the requirements of 40 CFR 52, Appendix E; 40 CFR 60 Appendix B; or 40 CFR 75, Appendix A.
 - B. The monitoring system shall comply with all applicable sections of R307-170; 40 CFR 13; and 40 CFR 60, Appendix B – Performance Specifications.
 - ii. Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9.
 - g. Petroleum Refineries.
 - i. Limits at Fluid Catalytic Cracking Units (FCCU)
 - A. FCCU SO₂ Emissions
 - I. Each owner or operator of an FCCU shall comply with an SO₂ emission limit of 25 ppmvd @ 0% excess air on a 365-day rolling average basis and 50 ppmvd @ 0% excess air on a 7-day rolling average basis.
 - II. Compliance with this limit shall be determined by following 40 C.F.R. §60.105a(g).
 - B. FCCU PM Emissions
 - I. Each owner or operator of an FCCU shall comply with an emission limit of 1.0 pounds PM per 1000 pounds burn-off.
 - II. Compliance with this limit shall be determined by following the stack test protocol specified in 40 C.F.R. §60.106(b) or 40 C.F.R. §60.104a(d) to measure PM emissions on the FCCU. Each owner operator shall conduct stack tests ~~once every three (3) years~~ annually at each FCCU.
 - III. No later than January 1, 2019, each owner or operator of an FCCU shall install, operate and maintain a continuous parameter monitor system (CPMS) to measure and record operating parameters from the FCCU for determination of source-wide particulate emissions as per the requirements of 40 CFR 60.105a(b)(1).
 - ii. Limits on Refinery Fuel Gas.
 - A. All petroleum refineries in or affecting any PM_{2.5} nonattainment area or any PM₁₀ nonattainment or maintenance area shall reduce the H₂S content of the refinery plant gas to 60 ppm or less as described in 40 CFR 60.102a. Compliance shall be

1 based on a rolling average of 365 days. The owner/operator shall comply with the
2 fuel gas monitoring requirements of 40 CFR 60.107a and the related recordkeeping
3 and reporting requirements of 40 CR 60.108a. As used herein, refinery “plant gas”
4 shall have the meaning of “fuel gas” as defined in 40 CFR 60.101a, and may be
5 used interchangeably.
6

7 B. For natural gas, compliance is assumed while the fuel comes from a public utility.
8

9 iii. Sulfur Removal Units
10

11 A. All petroleum refineries in or affecting any PM_{2.5} nonattainment area or any
12 PM₁₀ nonattainment or maintenance area shall require:
13

14 I. Sulfur removal units/plants (SRUs) that are at least 95% effective in
15 removing sulfur from the streams fed to the unit; or
16

17 II. SRUs that meet the SO₂ emission limitations listed in 40 CFR 60.102a(f)(1) or
18 60.102a(f)(2) as appropriate.
19

20 B. The amine acid gas and sour water stripper acid gas shall be processed in the
21 SRU(s).
22

23 C. Compliance shall be demonstrated by daily monitoring of flows to the SRU(s).
24 Continuous monitoring of SO₂ concentration in the exhaust stream shall be
25 conducted via CEM as outlined in IX.H.1.f above. Compliance shall be
26 determined on a rolling
27 30-day average.
28

29 iv. No Burning of Liquid Fuel Oil in Stationary Sources
30

31 A. No petroleum refineries in or affecting any PM_{2.5} nonattainment area or any PM₁₀
32 nonattainment or maintenance area shall be allowed to burn liquid fuel oil in
33 stationary sources except during natural gas curtailments or as specified in the
34 individual subsections of Section IX, Part H.
35

36 B. The use of diesel fuel meeting the specifications of 40 CFR 80.510 in
37 standby or emergency equipment is exempt from the limitation of
38 IX.H.1.g.iv.A above.
39

40 v. Requirements on Hydrocarbon Flares.
41

42 A. All hydrocarbon flares at petroleum refineries located in or affecting any PM_{2.5}
43 nonattainment area or any PM₁₀ nonattainment or maintenance area within the
44 State shall be subject to the flaring requirements of NSPS Subpart Ja (40 CFR
45 60.100a–109a), if not already subject under the flare applicability provisions of
46 Ja.
47

48 B. No later than January 1, 2019, all major source petroleum refineries in or affecting
49 any PM_{2.5} nonattainment area or an PM₁₀ nonattainment or maintenance area shall
50 either 1) install and operate a flare gas recovery system designed to limit
51 hydrocarbon flaring produced from each affected flare during normal operations to

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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. Flare gas recovery is not required for dedicated SRU flare and header systems, or HF flare and header systems.

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1 **H.2 Source Specific Emission Limitations in Salt Lake County PM₁₀**
2 **Nonattainment/Maintenance Area**

3
4 a. Big West Oil Company

5
6 i. Source-wide PM₁₀ Cap

7 No later than January 1, 2019, combined emissions of PM₁₀ shall not exceed 1.037 tons
8 per day (tpd).

9
10 A. Setting of emission factors:

11
12 The emission factors derived from the most current performance test shall be
13 applied to the relevant quantities of fuel combusted. Unless adjusted by
14 performance testing as discussed in IX.H.2.a.i.B below, the default emission
15 factors to be used are as follows:

16
17 Natural gas:
18 Filterable PM₁₀: 1.9 lb/MMscf
19 Condensable PM₁₀: 5.7 lb/MMscf

20
21 Plant gas:
22 Filterable PM₁₀: 1.9 lb/MMscf
23 Condensable PM₁₀: 5.7 lb/MMscf

24
25 Fuel Oil: The PM₁₀ emission factor shall be determined from the latest edition of
26 AP-42

27
28 Cooling Towers: The PM₁₀ emission factor shall be determined from the
29 latest edition of AP-42

30
31 FCC Stacks: The PM₁₀ emission factor shall be established by stack test.

32
33 Where mixtures of fuel are used in a Unit, the above factors shall be
34 weighted according to the use of each fuel.

35
36 B. The default emission factors listed in IX.H.2.a.i.A above apply until such time as
37 stack testing is conducted as outlined below:

38
39 PM₁₀ stack testing on the FCC shall be performed initially no later than January
40 1, 2019 and at least ~~once every three (3) years~~ annually thereafter. Stack testing
41 shall be performed as outlined in IX.H.1.e.

42
43 C. Compliance with the source-wide PM₁₀ Cap shall be determined for each
44 day as follows:

45
46 Total 24-hour PM₁₀ emissions for the emission points shall be calculated by

1 adding the daily results of the PM₁₀ emissions equations listed below for
2 natural gas, plant gas, and fuel oil combustion. These emissions shall be added
3 to the emissions from the cooling towers, and the FCCs to arrive at a combined
4 daily PM₁₀ emission total.

5
6 For purposes of this subsection a “day” is defined as a period of 24-
7 hours commencing at midnight and ending at the following midnight.

8
9 Daily gas consumption shall be measured by meters that can delineate the
10 flow of gas to the boilers, furnaces and the SRU incinerator.

11
12 The equation used to determine emissions from these units shall be as
13 follows: Emission Factor (lb/MMscf) * Gas Consumption (MMscf/24
14 hrs)/(2,000 lb/ton)

15
16 Daily fuel oil consumption shall be monitored by means of leveling gauges
17 on all tanks that supply combustion sources.

18
19 The daily PM₁₀ emissions from the FCC shall be calculated using the following
20 equation:

21
22
$$E = FR * EF$$

23
24 Where:

25 E = Emitted PM₁₀

26 FR = Feed Rate to Unit (kbbls/day)

27 EF = emission factor (lbs/kbbl), established by the most recent stack test

28
29 Results shall be tabulated for each day, and records shall be kept which include
30 the meter readings (in the appropriate units) and the calculated emissions.

31
32 ii. Source-Wide NO_x Cap

33
34 No later than January 1, 2019, combined emissions of NO_x shall not exceed 0.80 tons per
35 day (tpd) and 195 tons per rolling 12-month period.

36
37 A. Setting of emission factors:

38
39 The emission factors derived from the most current performance test shall be
40 applied to the relevant quantities of fuel combusted. Unless adjusted by
41 performance testing as discussed in IX.H.2.a.ii.B below, the default emission
42 factors to be used are as follows:

43
44 Natural gas: shall be determined from the latest edition of AP-42

45 Plant gas: assumed equal to natural gas

46 Diesel fuel: shall be determined from the latest edition of AP-42

1
2 Where mixtures of fuel are used in a Unit, the above factors shall be
3 weighted according to the use of each fuel.
4

- 5 B. The default emission factors listed in IX.H.2.a.ii.A above apply until such time as
6 stack testing is conducted as outlined below:
7

8 Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment
9 above 40 MMBtu/hr has been performed. NO_x emissions for the FCC are monitored
10 with a continuous emission monitoring system. Refinery Boilers and heaters over 40
11 MMBtu/hr but less than 100 MMBtu/hr are in compliance with monitoring and work
12 practice standards of Subpart DDDD of Part 63.
13

- 14 C. Compliance with the source-wide NO_x Cap shall be determined for each
15 day as follows:
16

17 Total 24-hour NO_x emissions shall be calculated by adding the emissions for each
18 emitting unit. The emissions for each emitting unit shall be calculated by
19 multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each
20 fuel combusted at each affected unit by the associated emission factor, and
21 summing the results.
22

23 Daily plant gas consumption at the furnaces, boilers and SRU incinerator
24 shall be measured by flow meters. The equations used to determine emissions
25 shall be as follows:
26

27
$$\text{NO}_x = \text{Emission Factor (lb/MMscf)} * \text{Gas Consumption (MMscf/24 hrs)} / (2,000$$

28
$$\text{lb/ton})$$
 Where the emission factor is derived from the fuel used, as listed in
29 IX.H.2.a.ii.A above
30

31 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
32 tanks that supply combustion sources.
33

34 The daily NO_x emissions from the FCC shall be calculated using a CEM as outlined
35 in IX.H.1.f
36

37 Total daily NO_x emissions shall be calculated by adding the results of the above NO_x
38 equations for natural gas and plant gas combustion to the estimate for the FCC.
39

40 For purposes of this subsection a “day” is defined as a period of 24-hours
41 commencing at midnight and ending at the following midnight.
42

43 Results shall be tabulated for each day, and records shall be kept which include
44 the meter readings (in the appropriate units) and the calculated emissions.
45

- 46 iii. Source-Wide SO₂ Cap

1
2 No later than January 1, 2019, combined emissions of SO₂ shall not exceed 0.60 tons
3 per day (tpd) and 140 tons per rolling 12-month period.
4

5 A. Setting of emission factors:
6

7 The emission factors derived from the most current performance test shall be
8 applied to the relevant quantities of fuel combusted. The default emission factors to
9 be used are as follows:
10

11 Natural Gas - 0.60 lb SO₂/MMscf gas
12

13 Plant Gas: The emission factor to be used in conjunction with plant gas
14 combustion shall be determined through the use of a CEM as outlined in
15 IX.H.1.f. .
16

17 SRUs: The emission rate shall be determined by multiplying the sulfur
18 dioxide concentration in the flue gas by the flow rate of the flue gas. The
19 sulfur dioxide concentration in the flue gas shall be determined by CEM as
20 outlined in IX.H.1.f.
21

22 Fuel oil: The emission factor to be used for combustion shall be calculated based on
23 the weight percent of sulfur, as determined by ASTM Method D-4294-89 or EPA-
24 approved equivalent acceptable to the Director, and the density of the fuel oil, as
25 follows:
26

27 $EF \text{ (lb SO}_2\text{/k gal)} = \text{density (lb/gal)} * (1000 \text{ gal/k gal)} * \text{wt. \% S}/100 * (64 \text{ lb SO}_2\text{/32}$
28 lb S)
29

30 Where mixtures of fuel are used in a Unit, the above factors shall be
31 weighted according to the use of each fuel.
32

33 B. Compliance with the source-wide SO₂ Cap shall be determined for each day as
34 follows: Total daily SO₂ emissions shall be calculated by adding the daily SO₂
35 emissions for natural gas and plant fuel gas combustion, to those from the FCC and
36 SRU stacks.
37

38 The daily SO_x emission from the FCC shall be calculated using a CEM as outlined in
39 IX.H.11.f.
40

41 Daily natural gas and plant gas consumption shall be determined through the
42 use of flow meters.
43

44 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
45 tanks that supply combustion sources.
46

1 For purposes of this subsection a “day” is defined as a period of 24-hours
2 commencing at midnight and ending at the following midnight.

3
4 Results shall be tabulated for each day, and records shall be kept which include
5 CEM readings for H₂S (averaged for each day), all meter reading (in the
6 appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel
7 oil is burned), and the calculated emissions.

8
9 iv. Emergency and Standby Equipment

10
11 A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is
12 allowed in standby or emergency equipment at all times.

13
14 v. Alternate Startup and Shutdown Requirements

15
16 A. During any day which includes startup or shutdown of the FCCU, combined
17 emissions of SO₂ shall not exceed 1.2 tons per day (tpd). For purposes of this
18 subsection, a "day" is defined as a period of 24-hours commencing at midnight and
19 ending at the following midnight.

20
21 B. The total number of days which include startup or shutdown of the FCCU shall
22 not exceed ten (10) per 12-month rolling period.

23
24 vi. Requirements on Hydrocarbon Flares

25
26 A. No later than January 1, 2021, routine flaring will be limited to 300,000 scfd for
27 each affected flare ~~[from October 1 through March 31 and 500,000 scfd for each~~
28 ~~affected flare for the balance of the year].~~

29
30 vii. No later than January 1, 2019, the owner/operator shall install the following to control
31 emissions from the listed equipment:

Emission Unit	Control Equipment
FCCU Regenerator	Flue gas blowback “Pall Filter”, quaternary cyclones with fabric filter
H-404 #1 Crude Heater	Ultra-low NO _x burners
Refinery Flares	Subpart Ja, and MACT CC flaring standards
SRU	Tail gas incinerator and redundant caustic scrubber
Product Loading Racks	Vapor recovery and vapor combustors
Wastewater Treatment System	API separator fixed cover, carbon adsorber canisters to be installed 2019.

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- b. Bountiful City Light and Power: Power Plant
 - i. Emissions to the atmosphere shall not exceed the following rates and concentrations:
 - A. GT #1 (5.3 MW Turbine)
Exhaust Stack: 0.6 g NO_x / kW-hr
 - B. GT #2 and GT #3 (each TITAN Turbine) Exhaust Stack: 7.5 lb NO_x / hr
 - ii. Compliance to the above emission limitations shall be determined by stack test. Stack testing shall be performed as outlined in IX.H.1.e.
 - A. Initial stack tests have been performed. Each turbine shall be tested at least once per year.
 - iii. Combustion Turbine Startup / Shutdown Emission Minimization Plan
 - A. Startup begins when natural gas is supplied to the combustion turbine(s) with the intent of combusting the fuel to generate electricity. Startup conditions end within sixty (60) minutes of natural gas being supplied to the turbine(s).
 - B. Shutdown begins with the initiation of the stop sequence of a turbine until the cessation of natural gas flow to the turbine.
 - C. Periods of startup or shutdown shall not exceed two (2) hours per combustion turbine per day.

1 c. Central Valley Water Reclamation Facility: Wastewater Treatment Plant

2 i. NO_x emissions from the operation of all engines at the plant shall not exceed 0.648
3 tons per day.

4
5 ii. Compliance with the emission limitation shall be determined by summing the
6 emissions from all the engines. Emission from each engine shall be calculated from
7 the following equation:

8
9 Emissions (tons/day) = (Power production in kW-hrs/day) x (Emission
10 factor in grams/kW- hr) x (1 lb/453.59 g) x (1 ton/2000 lbs)

11
12 A. Stack tests shall be performed in accordance with IX.H.1.e. Each engine shall
13 be tested at least ~~every three years from the previous test~~ annually.

14
15 B. The NO_x emission factor for each engine shall be derived from the most recent
16 stack test.

17
18 C. NO_x emissions shall be calculated on a daily basis.

19
20 D. A day is equivalent to the time period from midnight to the following
21 midnight.

22
23 E. The number of kilowatt hours generated by each engine shall be determined
24 by examination of electrical meters, which shall record electricity
25 production on a continuous basis.

1 d. Chevron Products Company

2
3 i. Source-wide PM₁₀ Cap

4 No later than January 1, 2019, combined emissions of PM₁₀ shall not exceed 0.715 tons
5 per day (tpd).

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7 A. Setting of emission factors:

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9 The emission factors derived from the most current performance test shall be
10 applied to the relevant quantities of fuel combusted. Unless adjusted by
11 performance testing as discussed in IX.H.2.d.i.B below, the default emission factors
12 to be used are as follows:

13
14 Natural gas:

15 Filterable PM₁₀: 1.9 lb/MMscf

16 Condensable PM₁₀: 5.7 lb/MMscf

17
18 Plant gas:

19 Filterable PM₁₀: 1.9 lb/MMscf

20 Condensable PM₁₀: 5.7 lb/MMscf

21
22 HF alkylation polymer: shall be determined from the latest edition of AP-42 (HF
23 alkylation polymer treated as fuel oil #6)

24
25 Diesel fuel: shall be determined from the latest edition of AP-42

26
27 Cooling Towers: shall be determined from the latest edition of AP-42

28
29 FCC Stack:

30 The PM₁₀ emission factors shall be based on the most recent stack test and verified
31 by parametric monitoring as outlined in IX.H.1.g.i.B.III

32
33 Where mixtures of fuel are used in a Unit, the above factors shall be
34 weighted according to the use of each fuel.

35
36 B. The default emission factors listed in IX.H.2.d.i.A above apply until such time as
37 stack testing is conducted as outlined below:

38
39 Initial PM₁₀ stack testing on the FCC stack has been performed and shall be
40 conducted at least ~~[once every three (3) years from the date of the last stack-~~
41 ~~test]annually~~. Stack testing shall be performed as outlined in IX.H.1.e.

42
43 C. Compliance with the source-wide PM₁₀ Cap shall be determined for each
44 day as follows:

45
46 Total 24-hour PM₁₀ emissions for the emission points shall be calculated by adding

1 the daily results of the PM₁₀ emissions equations listed below for natural gas, plant
2 gas, and fuel oil combustion. These emissions shall be added to the emissions
3 from the cooling towers, and the FCC to arrive at a combined daily PM₁₀ emission
4 total. For purposes of this subsection a “day” is defined as a period of 24-hours
5 commencing at midnight and ending at the following midnight.

6
7 Daily natural gas and plant gas consumption shall be determined through the
8 use of flow meters.

9
10 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
11 tanks that supply combustion sources.

12
13 The equation used to determine emissions for the boilers and furnaces shall
14 be as follows:

15 Emission Factor (lb/MMscf) * Gas Consumption (MMscf/24 hrs)/(2,000
16 lb/ton) Results shall be tabulated for each day, and records shall be kept which
17 include the meter readings (in the appropriate units) and the calculated
18 emissions.

19
20 ii. Source-wide NO_x Cap

21 No later than January 1, 2019, combined emissions of NO_x shall not exceed 2.1 tons per day
22 (tpd) and 766.5 tons per rolling 12-month period.

23
24 A. Setting of emission factors:

25
26 The emission factors derived from the most current performance test shall be applied to
27 the relevant quantities of fuel combusted. Unless adjusted by performance testing as
28 discussed in IX.H.2.d.ii.B below, the default emission factors to be used are as follows:

29
30 Natural gas: shall be determined from the latest edition of AP-42 Plant gas: assumed
31 equal to natural gas

32
33 Alkylation polymer: shall be determined from the latest edition of AP-42 (as fuel oil
34 #6)

35 Diesel fuel: shall be determined from the latest edition of AP-42

36
37 Where mixtures of fuel are used in a Unit, the above factors shall be weighted
38 according to the use of each fuel.

39
40 B. The default emission factors listed in IX.H.2.d.ii.A above apply until such time as stack
41 testing is conducted as outlined below:

42
43 Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment above
44 100 MMBtu/hr has been performed and shall be conducted at least ~~[once every three (3)
45 years from the date of the last stack test]~~ annually. At that time a new flow-weighted
46 average emission factor in terms of: lbs/MMbtu shall be derived. Stack testing shall be

1 performed as outlined in IX.H.1.e.

- 2
3 C. Compliance with the source-wide NO_x Cap shall be determined for each day as
4 follows:

5
6 Total 24-hour NO_x emissions shall be calculated by adding the emissions for each
7 emitting unit. The emissions for each emitting unit shall be calculated by multiplying
8 the hours of operation of a unit, feed rate to a unit, or quantity of each fuel combusted
9 at each affected unit by the associated emission factor, and summing the results.

10
11 A NO_x CEM shall be used to calculate daily NO_x emissions from the FCC. Emissions
12 shall be determined by multiplying the nitrogen dioxide concentration in the flue gas by
13 the flow rate of the flue gas. The NO_x concentration in the flue gas shall be determined
14 by a CEM as outlined in IX.H.1.f.

15
16 For purposes of this subsection a “day” is defined as a period of 24-hours commencing
17 at midnight and ending at the following midnight.

18
19 Daily natural gas and plant gas consumption shall be determined through the use of
20 flow meters.

21
22 Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks
23 that supply combustion sources.

24
25 Results shall be tabulated for each day, and records shall be kept which include the
26 meter readings (in the appropriate units) and the calculated emissions.

27
28 iii. Source-wide SO₂ Cap

29 No later than January 1, 2019, combined emissions of SO₂ shall not exceed 1.05 tons per day
30 (tpd) and 383.3 tons per rolling 12-month period.

31
32 A Setting of emission factors:

33
34 The emission factors derived from the most current performance test shall be applied to
35 the relevant quantities of fuel combusted. The default emission factors to be used are as
36 follows:

37
38 FCC: The emission rate shall be determined by the FCC SO₂ CEM as outlined in
39 IX.H.1.f.

40
41 SRUs: The emission rate shall be determined by multiplying the sulfur dioxide
42 concentration in the flue gas by the flow rate of the flue gas. The sulfur dioxide
43 concentration in the flue gas shall be determined by CEM as outlined in IX.H.1.f.

44
45 Natural gas: EF = 0.60 lb/MMscf
46

1 Fuel oil & HF Alkylation polymer: The emission factor to be used for combustion shall
2 be calculated based on the weight percent of sulfur, as determined by ASTM Method D-
3 4294-89 or EPA-approved equivalent acceptable to the Director, and the density of the
4 fuel oil, as follows:

5
6
$$EF \text{ (lb SO}_2\text{/k gal)} = \text{density (lb/gal)} * (1000 \text{ gal/k gal)} * \text{wt.\% S/100} * (64 \text{ lb SO}_2\text{/32 lb S)}$$

7

8 Plant gas: the emission factor shall be calculated from the H₂S measurement obtained
9 from the H₂S CEM.

10
11 Where mixtures of fuel are used in a Unit, the above factors shall be weighted
12 according to the use of each fuel.

13
14 B. Compliance with the source-wide SO₂ Cap shall be determined for each day as follows:

15
16 Total daily SO₂ emissions shall be calculated by adding the daily SO₂ emissions for
17 natural gas and plant fuel gas combustion, to those from the FCC and SRU stacks.

18
19 Daily natural gas and plant gas consumption shall be determined through the use of
20 flow meters.

21
22 Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks
23 that supply combustion sources.

24
25 Results shall be tabulated for each day, and records shall be kept which include CEM
26 readings for H₂S (averaged for each one-hour period), all meter reading (in the
27 appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel oil
28 is burned), and the calculated emissions.

29
30 iv. Emergency and Standby Equipment and Alternative Fuels

31
32 A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed
33 in standby or emergency equipment at all times.

34
35 B. HF alkylation polymer may be burned in the Alky Furnace (F-
36 36017).

37
38 C. Plant coke may be burned in the FCC Catalyst Regenerator.

39
40 v. Compressor Engine Requirements

41
42 A. Emissions of NO_x from each rich-burn compressor engine shall not exceed the
43 following:

44
Engine Number NO_x in ppmvd @ 0% O₂

K35001	236
K35002	208
K35003	230

B Initial stack testing to demonstrate compliance with the above emission limitations shall be performed no later than January 1, 2019 and at least ~~once every three (3) years~~ annually thereafter. Stack testing shall be performed as outlined in IX.H.1.e.

vi. Flare Calculation

A. Chevron's Flare #3 receives gases from its Isomerization unit, Reformer unit as well as its HF Alkylation Unit. The HF Alkylation Unit's flow contribution to Flare #3 will not be included in determining compliance with the flow restrictions set in IX.H.1.g.v.B

i. No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:

Emission Unit	Control Equipment
Boilers: 5, 6, 7	Low NOx burners and flue gas recirculation (FGR)
Cooling Water Towers	High efficiency drift eliminators
Crude Furnaces F21001, F21002	Low NOx burners
Crude Oil Loading	Vapor Combustion Unit (VCU)
FCC Regenerator Stack	Vacuum gas oil hydrotreater, Electrostatic precipitator (ESP) and cyclones
Flares: Flare 1, 2, 3	Flare gas recovery system
HDS Furnaces F64010, F64011	Low NOx burners
Reformer Compressor Drivers K35001, K35002, K35003	Selective Catalytic Reduction (SCR)
Sulfur Recovery Unit 1	Tail gas treatment unit and tail gas incineration
Sulfur Recovery Unit 2	Tail gas treatment unit and tail gas incineration
Wastewater Treatment Plant	Existing wastewater controls system of induced air flotation (IAF) and regenerative thermal oxidation (RTO)

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e. Hexcel Corporation: Salt Lake Operations

- i. The following limits shall not be exceeded for fiber line operations:
 - A. 5.50 MMscf of natural gas consumed per day.
 - B. 0.061 MM pounds of carbon fiber produced per day.
 - C. Compliance with each limit shall be determined by the following methods:
 - I. Natural gas consumption shall be determined by examination of natural gas billing records for the plant and onsite pipe-line metering.
 - II. Fiber production shall be determined by examination of plant production records.
 - III. Records of consumption and production shall be kept on a daily basis for all periods when the plant is in operation.
- ii. After a shutdown and prior to startup of fiber lines 13, 14, 15, or 16, the line's baghouse(s) shall be started and remain in operation during production.
 - A. During fiber line production, the static pressure differential across the filter media shall be within the manufacturer's recommended range and shall be recorded daily.
 - B. The manometer or the differential pressure gauge shall be calibrated according to the manufacturer's instructions at least once every 12 months.

1 f. Holly Refining and Marketing Company

2
3 i. Source-wide PM₁₀ Cap

4 No later than January 1, 2019, PM₁₀ emissions from all sources shall not exceed 0.416
5 tons per day (tpd).

6
7 A. Setting of emission factors:

8
9 The emission factors derived from the most current performance test shall be
10 applied to the relevant quantities of fuel combusted. Unless adjusted by
11 performance testing as discussed in IX.H.2.g.i.B below, the default emission factors
12 to be used are as follows:

13
14 Natural gas or Plant gas:

15 non-NSPS combustion equipment: 7.65 lb PM₁₀/MMscf

16 NSPS combustion equipment: 0.52 lb PM₁₀/MMscf

17
18 Fuel oil:

19 The filterable PM₁₀ emission factor for fuel oil combustion shall be determined
20 based on the sulfur content of the oil as follows:

21
22
$$PM_{10} \text{ (lb/1000 gal)} = (10 * \text{wt. \% S}) + 3.22$$

23
24 The condensable PM₁₀ emission factor for fuel oil combustion shall be
25 determined from the latest edition of AP-42.

26
27 Cooling Towers: The PM₁₀ emission factor shall be determined from the latest
28 edition of AP-42.

29
30 FCC Wet Scrubbers:

31 The PM₁₀ emission factors shall be based on the most recent stack test and
32 verified by parametric monitoring as outlined in IX.H.1.g.i.B.III. As an alternative
33 to a continuous parameter monitor system or continuous opacity monitoring
34 system for PM emissions from any FCCU controlled by a wet gas scrubber, as
35 required in Subsection IX.H.1.g.i.B.III, the owner/operator may satisfy the
36 opacity monitoring requirements from its FCC Units with wet gas scrubbers
37 through an alternate monitoring program as approved by the EPA and acceptable
38 to the Director.

39
40 B. The default emission factors listed in IX.H.2.f.i.A above apply until such time as
41 stack testing is conducted as outlined below:

42
43 Initial stack testing on all NSPS combustion equipment shall be conducted no later
44 than January 1, 2019 and at least ~~[once every three (3) years thereafter]~~ annually. At
45 that time a new flow-weighted average emission factor in terms of: lb
46 PM₁₀/MMBtu shall be derived. Stack testing shall be performed as outlined in

IX.H.1.e.

C. Compliance with the source-wide PM₁₀ Cap shall be determined for each day as follows:

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 wet scrubbers to arrive at a combined daily PM₁₀ emission total.

For purposes of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

Daily natural gas and plant gas consumption shall be determined through the use of flow meters on all gas-fueled combustion equipment.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply fuel oil to combustion sources.

The equations used to determine emissions for the boilers and furnaces shall be as follows:

Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural/Plant Gas Consumption (MMscf/day)/(2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/day)/(2,000 lb/ton)

Results shall be tabulated for each day, and records shall be kept which include all meter readings (in the appropriate units), and the calculated emissions.

ii. Source-wide NO_x Cap

No later than January 1, 2019, NO_x emissions into the atmosphere from all emission points shall not exceed 347.1 tons per rolling 12-month period and 2.09 tons per day (tpd).

A. Setting of emission factors:

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 as discussed in IX.H.2.g.ii.B below, the default emission factors to be used are as follows:

1 Natural gas/refinery fuel gas combustion using:
2 Low NO_x burners (LNB): 41 lbs/MMscf
3 Ultra-Low NO_x (ULNB) burners: 0.04 lbs/MMbtu
4 Next Generation Ultra Low NO_x burners (NGULNB): 0.10 lbs/MMbtu
5 Selective catalytic reduction (SCR): 0.02 lbs/MMbtu
6 All other combustion burners: 100 lb/MMscf
7

8 Where:

9 "Natural gas/refinery fuel gas" shall represent any combustion of natural gas,
10 refinery fuel gas, or combination of the two in the associated burner.
11

12 All fuel oil combustion: 120 lbs/Kgal
13

14 B. The default emission factors listed in IX.H.2.f.ii.A above apply until such time as
15 stack testing is conducted as outlined in IX.H.1.e or by NSPS.
16

17 C. Compliance with the Source-wide NO_x Cap shall be determined for each
18 day as follows:
19

20 Total daily NO_x emissions for emission points shall be calculated by adding the
21 results of the NO_x equations for plant gas, fuel oil, and natural gas combustion
22 listed below. For purposes of this subsection a "day" is defined as a period of 24-
23 hours commencing at midnight and ending at the following midnight.
24

25 Daily natural gas and plant gas consumption shall be determined through the
26 use of flow meters.
27

28 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
29 tanks that supply combustion sources.
30

31 The equations used to determine emissions for the boilers and furnaces shall
32 be as follows:
33

34 Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural Gas Consumption
35 (MMscf/day)/(2,000 lb/ton)
36

37 Emissions (tons/day) = Emission Factor (lb/MMscf) * Plant Gas Consumption
38 (MMscf/day)/(2,000 lb/ton)
39

40 Emissions (tons/day) = Emission Factor (lb/MMBTU) * Burner Heat Rating
41 (BTU/hr) * 24 hours per day / (2,000 lb/ton)
42

43 Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption
44 (kgal/day)/(2,000 lb/ton)
45

46 Results shall be tabulated for each day; and records shall be kept which include

1 the meter readings (in the appropriate units), emission factors, and the
2 calculated emissions.

3
4 iii. Source-wide SO₂ Cap

5 No later than January 1, 2019, the emission of SO₂ from all emission points (excluding
6 routine SRU turnaround maintenance emissions) shall not exceed 110.3 tons per rolling
7 12-month period and 0.31 tons per day (tpd).

8
9 A. Setting of emission factors:

10 The emission factors listed below shall be applied to the relevant quantities of
11 fuel combusted:

12
13 Natural gas - 0.60 lb SO₂/MMscf

14
15 Plant gas - The emission factor to be used in conjunction with plant gas
16 combustion shall be determined through the use of a CEM which will measure
17 the H₂S content of the fuel gas. The CEM shall operate as outlined in IX.H.1.f.

18
19 Fuel oil - The emission factor to be used in conjunction with fuel oil combustion
20 shall be calculated based on the weight percent of sulfur, as determined by
21 ASTM Method D-4294-89 or EPA-approved equivalent, and the density of the
22 fuel oil, as follows:

23
24 $(\text{lb of SO}_2/\text{kgal}) = (\text{density lb/gal}) * (1000 \text{ gal/kgal}) * (\text{wt. \%S})/100 * (64 \text{ g SO}_2/32$
25 $\text{g S})$

26
27 The weight percent sulfur and the fuel oil density shall be recorded for each day
28 any fuel oil is combusted.

29
30 B. Compliance with the Source-wide SO₂ Cap shall be determined for each
31 day as follows:

32
33 Total daily SO₂ emissions shall be calculated by adding daily results of the SO₂
34 emissions equations listed below for natural gas, plant gas, and fuel oil combustion.
35 For purposes of this subsection a “day” is defined as a period of 24-hours
36 commencing at midnight and ending at the following midnight.

37
38 The equations used to determine emissions are:

39
40 $\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Natural Gas Consumption}$
41 $(\text{MMscf/day})/(2,000 \text{ lb/ton})$

42
43 $\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Plant Gas Consumption}$
44 $(\text{MMscf/day})/(2,000 \text{ lb/ton})$

45
46 $\text{Emissions (tons/day)} = \text{Emission Factor (lb/kgal)} * \text{Fuel Oil Consumption}$

(kgal/24 hrs)/(2,000 lb/ton)

For purposes of these equations, fuel consumption shall be measured as outlined below:

Daily natural gas and plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources.

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 reading (in the appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel oil is burned), and the calculated emissions.

iv. Emergency and Standby Equipment

A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in standby or emergency equipment at all times.

v. No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:

1)

Emission Unit	Control Equipment
Process heaters and boilers	Boilers 8&11: LNB+SCR Boilers 5, 9 & 10: SCR Process heaters 20H2, 20H3 23H1, 24H1, 25H1: ULNB
Cooling water towers 10, 11	High efficiency drift eliminators
FCCU regenerator stacks	WGS with Lo-TOx
Flares	Flare gas recovery system
Sulfur recovery unit	Tail gas incineration and WGS with Lo-TOx
Wastewater treatment plant	API separators, dissolved gas floatation (DGF), moving bed bio-film reactors (MBBR)

1 g. Kennecott Utah Copper (KUC): Mine

2 i. Bingham Canyon Mine (BCM)

- 3
4 A. Maximum total mileage per calendar day for ore and waste haul trucks shall not exceed
5 30,000 miles.

6
7 KUC shall keep records of daily total mileage for all periods when the mine is in
8 operation. KUC shall track haul truck miles with a Global Positioning System or
9 equivalent. The system shall use real time tracking to determine daily mileage.

- 10
11 B. To minimize fugitive dust on roads at the mine, the owner/operator shall
12 perform the following measures:

13
14 I. Apply water to all active haul roads as weather and operational conditions warrant
15 except during precipitation or freezing weather conditions, and shall apply a
16 chemical dust suppressant to active haul roads located outside of the pit influence
17 boundary no less than twice per year.

18
19 II. Chemical dust suppressant shall be applied as weather and operational conditions
20 warrant except during precipitation or freezing weather conditions on unpaved
21 access roads that receive haul truck traffic and light vehicle traffic.

22
23 III. Records of water and/or chemical dust control treatment shall be kept for all
24 periods when the BCM is in operation.

25
26 IV. KUC is subject to the requirements in the most recent federally approved Fugitive
27 Emissions and Fugitive Dust rules.

- 28
29 C. To minimize emissions at the mine, the owner/operator shall:

30
31 I. Control emissions from the in-pit crusher with a
32 baghouse.

- 33
34 D. Implementation Schedule

35
36 KUC shall purchase new haul trucks with the highest engine Tier level available which
37 meet mining needs. KUC shall maintain records of haul trucks purchased and retired

38
39 ii. Copperton Concentrator (CC)

- 40
41 A. Control emissions from the Product Molybdenite Dryers with a scrubber during
42 operation of the dryers.

43
44 During operation of the dryers, the static pressure differential between the inlet and
45 outlet of the scrubber shall be within the manufacturer's recommended range and shall
46 be recorded weekly.

47
48 The manometer or the differential pressure gauge shall be calibrated according to the
49 manufacturer's instructions at least once per year.

1 h. Kennecott Utah Copper (KUC): Power Plant and Tailings Impoundment

2 i. Utah Power Plant

3 A. Boilers #1, #2, and #3 shall not operate.

4 B. Unit #5 shall not exceed the following emission rates to the atmosphere:

5 Pollutant	lb/hr	lb/event	ppmdv (15% O ₂ dry)
-------------	-------	----------	-----------------------------------

6
7
8 I. PM₁₀ with duct firing:

9 Filterable + condensable 18.8

10
11 II. NO_x:

12 Startup/shutdown 395 2.0

13
14 III. Startup / Shutdown Limitations:

15
16 1. The total number of startups and shutdowns together shall not exceed 690
17 per calendar year.

18
19 2. The NO_x emissions shall not exceed 395 lbs from each startup/shutdown
20 event, which shall be determined using manufacturer data.

21
22 3. Definitions:

23
24 (i) Startup cycle duration ends when the unit achieves half of the
25 design electrical generation capacity.

26
27 (ii) Shutdown duration cycle begins with the initiation of turbine
28 shutdown sequence and ends when fuel flow to the gas turbine is
29 discontinued.

30
31 C. Upon commencement of operation of Unit #5*, stack testing to demonstrate
32 compliance with the emission limitations in IX.H.2.h.i.B shall be performed as
33 follows for the following air contaminants

34
35 * Initial compliance testing for the natural gas turbine and duct burner is required.
36 The initial test date shall be performed within 60 days after achieving the
37 maximum heat input capacity production rate at which the affected facility will be
38 operated and in no case later than 180 days after the initial startup of a new
39 emission source.

40
41 The limited use of natural gas during maintenance firings and break-in firings does
42 not constitute operation and does not require stack testing.

43 Pollutant	Test Frequency
--------------	----------------

44
45 I. PM₁₀ every year

46
47 II. NO_x every year
48

1
2 D. The following requirements are applicable to Unit #4 ~~[- during the period November 1-~~
3 ~~to February 28/29 inclusive:]~~

4
5 I. ~~[During the period from November 1, to the last day in February inclusive,~~
6 ~~o]Only natural gas shall [only]~~ be used as a fuel, unless the supplier or
7 transporter of natural gas imposes a curtailment. The power plant may then
8 burn coal, only for the duration of the curtailment plus sufficient time to empty
9 the coal bins following the curtailment. The Director shall be notified of the
10 curtailment within 48 hours of when it begins and within 48 hours of when it
11 ends.

12
13 II. When burning natural gas the emissions to the atmosphere from the
14 indicated emission point shall not exceed the following rates and
15 concentrations:

Pollutant	grains/dscf	ppmdv (3% O ₂)
68 ⁰ F, 29.92 in. Hg		

16
17
18
19
20 1. PM₁₀ Units #1, #2, #3 and #4

filterable	0.004
filterable + condensable	0.03

21
22
23
24
25
26 2. NO_x*

27
28 *NO_x emissions from Unit #4 are limited to the more stringent limit in
29 Part H.12.k.i.

30
31 III. When using coal as a fuel during a curtailment of the natural gas supply,
32 emissions to the atmosphere from the indicated emission point shall not exceed
33 the following rates and concentrations:

Pollutant	grains/dscf	ppmdv (3% O ₂)
68 ⁰ F, 29.92 in Hg		

34
35
36
37
38 ~~1. [Units #1, #2 and #3-~~
39 ~~(i) PM₁₀~~

filterable	0.029
filterable + condensable	0.29

40
41
42
43
44
45
46 ~~2.]~~ Unit #4
47 (i) PM₁₀

filterable	0.029
filterable + condensable	0.29

1
2 (ii) NO_x*

3
4 *NO_x emissions from Unit #4 are limited to the more stringent limit in
5 Part H.12.k.i.
6

7 IV. If the units operated during the months specified above, stack testing to show
8 compliance with the emission limitations in H.2.h.i.D.II and III shall be performed
9 as follows for the following air contaminants:

10
11

Pollutant	Test Frequency	Initial Test
1. PM ₁₀	every year	#

12
13
14

15
16 # Initial testing shall be performed when burning natural gas and
17 also when burning coal as fuel. The initial test date shall be
18 performed within 60 days after achieving the maximum heat
19 input capacity production rate at which the affected facility will
20 be operated and in no case later than 180 days after the initial
21 startup of a new emission source.
22

23 The limited use of natural gas during maintenance firings and
24 break-in firings does not constitute operation and does not
25 require stack testing.
26

27 E. ~~[The following requirements are applicable to Unit[s] #1, #2, #3, and] #4 during the~~
28 ~~period March 1 to October 1 inclusive:~~

29
30 I. ~~Emissions to the atmosphere from the indicated emission point shall not exceed~~
31 ~~the following rates and concentrations:~~

32
33 ~~Pollutant _____ grains/dscf _____ ppmdv (3% O₂)~~
34 ~~68°F, 29.92 in Hg~~

35
36 ~~[1. Units #1, #2, and #3~~

37 ~~(i) PM₁₀ filterable _____ 0.029~~

38 ~~(ii) filterable +~~
39 ~~condensable _____ 0.29~~

40
41 ~~(iii) NO_x Units #1, #2, and #3 _____ 426.5]~~

42
43
44 ~~2. Unit #4~~

45 ~~(i) PM₁₀ filterable _____ 0.029~~

46
47 ~~(ii) NO_x* _____ [384]~~

48
49 ~~*NO_x emissions from Unit #4 are limited to the more stringent limit~~
50 ~~in Part H.12.k.i.~~
51

1 ~~H. If the units operated during the months specified above, stack testing to~~
2 ~~show compliance with the emission limitations in H.2.h.i.E.I shall be~~
3 ~~performed as follows for the following air contaminants:~~

4 ~~Pollutant ————— Test Frequency~~

5 ~~1. PM₁₀ ————— every year~~

6 ~~{2. NO_x ————— every year}~~

7
8 ~~The limited use of natural gas during maintenance firings and break in~~
9 ~~firings does not constitute operation and does not require stack testing.~~

10
11
12 ~~F.]~~ The sulfur content of any fuel burned shall not exceed 0.66 lb of sulfur per
13 million BTU per test.

14
15 I. Coal increments will be collected using ASTM 2234, Type I conditions A, B, or
16 C and systematic spacing.

17
18 II. Percent sulfur content and gross calorific value of the coal on a dry basis will
19 be determined for each gross sample using ASTM D methods 2013, 3177,
20 3173, and 2015.

21
22 III. KUC shall measure at least 95% of the required increments in any one month
23 that coal is burned in Unit #4.

24
25 ii. Tailings Impoundment

26
27 A. No more than 50 contiguous acres or more than 5% of the total tailings area
28 shall be permitted to have the potential for wind erosion.

29
30 I. Wind erosion potential is the area that is not wet, frozen, vegetated,
31 crusted, or treated and has the potential for wind erosion.

32
33 II. KUC shall conduct wind erosion potential grid inspections monthly
34 between February 15 and November 15. The results of the inspections
35 shall be used to determine wind erosion potential.

36
37 III. If KUC or the Director of Utah Division of Air Quality (Director) determines
38 that the percentage of wind erosion potential is exceeded, KUC shall meet
39 with the Director, to discuss additional or modified fugitive dust
40 controls/operational practices, and an implementation schedule for such,
41 within five working days following verbal notification by either party.

42
43 B. If between February 15 and November 15 KUC's daily weather forecast using
44 surrounding area meteorological data is for a wind event (a wind event is defined as
45 wind gusts exceeding 25 mph for more than one hour) the procedures listed below
46 shall be followed within 48 hours of issuance of the forecast. KUC shall:

47
48 I. Alert the Utah Division of Air Quality promptly.

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2
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4
5

II. Continue surveillance and coordination of appropriate measures.

C. KUC is subject to the requirements of the most recent federally approved Fugitive Emissions and Fugitive Dust rules.

DRAFT

1 Kennecott Utah Copper (KUC): Smelter & Refinery

2 i. Smelter

3
4 A Emissions to the atmosphere from the indicated emission points shall not exceed
5 the following rates and concentrations:

6
7 I. Main Stack (Stack No. 11)

- 8
9
10
11
12
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21
1. PM₁₀
 - a. 89.5 lbs/hr (filterable)
 - b. 439 lbs/hr (filterable + condensable)
 2. SO₂
 - a. 552 lbs/hr (3 hr. rolling average)
 - b. 422 lbs/hr (daily average)
 3. NO_x
 - a. 154 lbs/hr (daily average)

II. Holman Boiler

1. NO_x
 - a. 14.0 lbs/hr (calendar -day average)

B. Stack testing to show compliance with the emissions limitations of Condition (A)
above shall be performed as specified below:

Emission Point	Pollutant	Test Frequency
I. Main Stack (Stack No. 11)	PM ₁₀	every year
	SO ₂	CEM
	NO _x	CEM
II. Holman Boiler	NO _x	every three year[s] & CEMS or alternate method according NSPS standards

22
23 C. KUC must operate and maintain the air pollution control equipment and monitoring
24 equipment in a manner consistent with good air pollution control practices for
25 minimizing emissions at all times including during startup, shutdown, and malfunction.

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ii. Refinery:

A. Emissions to the atmosphere from the indicated emission point shall not exceed the following rate:

Emission Point	Pollutant	Maximum Emission Rate
The sum of two (Tankhouse) Boilers	NO _x	9.5 lbs/hr
Combined Heat Plant	NO _x	5.96 lbs/hr

B. Stack testing to show compliance with the above emission limitations shall be performed as follows:

Emission Point	Pollutant	Testing Frequency
Tankhouse Boilers	NO _x	every three year[s*]
Combined Heat Plant	NO _x	every year

~~[*Stack testing shall be performed on boilers that have operated at least 300 hours during a three year period.]~~

C. KUC must operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

1 j. PacifiCorp Energy: Gadsby Power Plant

2
3 i. Steam Generating Unit #1:

4 A. Emissions of NO_x shall be no greater than 179 lbs/hr on a three (3) hour block
5 average basis.

6
7 B. Emissions of NO_x shall not exceed 336 ppmvd (@ 3% O₂, dry)

8
9 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
10 CEM consisting of NO_x and O₂ monitors to determine compliance with the NO_x
11 limitation. The CEM shall operate as outlined in IX.H.1.f.

12
13 ii. Steam Generating Unit #2:

14 A. Emissions of NO_x shall be no greater than 204 lbs/hr on a three (3) hour block
15 average basis.

16
17 B. Emissions of NO_x shall not exceed 336 ppmvd (@ 3% O₂, dry)

18
19 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
20 continuous emission monitoring system (CEMS) consisting of NO_x and O₂
21 monitors to determine compliance with the NO_x limitation.

22
23 iii. Steam Generating Unit #3:

24 A. Emissions of NO_x shall be no greater than

25 I. 142 lbs/hr on a three (3) hour block average basis [~~-, applicable between~~
26 ~~November 1 and February 28/29~~

27 ~~II. 203 lbs/hr on a three (3) hour block average basis, applicable between March 1~~
28 ~~and October 31].~~

29
30 II. Emissions of NO_x shall not exceed 168 ppmvd (@ 3% O₂, dry) [~~-, applicable~~
31 between November 1 and February 28/29].

32
33 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
34 CEM consisting of NO_x and O₂ monitors to determine compliance with the NO_x
35 limitation. The CEM shall operate as outlined in IX.H.1.f.

36
37 iv. Steam Generating Units #1-3:

38
39 A. The owner/operator shall use only natural gas as a primary fuel and No. 2 fuel
40 oil or better as back-up fuel in the boilers. The No. 2 fuel oil may be used only
41 during periods of natural gas curtailment and for maintenance firings.

42 Maintenance firings shall not exceed one-percent of the annual plant Btu
43 requirement. In addition, maintenance firings shall be scheduled between April
44 1 and November 30 of any calendar year. Records of fuel oil use shall be kept
45 and they shall show the date the fuel oil was fired, the duration in hours the fuel
46 oil was fired, the amount of fuel oil consumed during each curtailment, and the

1 reason for each firing.

2
3 v. Natural Gas-fired Simple Cycle, Catalytic-controlled Turbine Units:

4 A. Total emissions of NO_x from all three turbines shall be no greater than 600 lbs/day.
5 For purposes of this subsection a “day” is defined as a period of 24-hours
6 commencing at midnight and ending at the following midnight.
7

8 B. Emissions of NO_x from each turbine stack shall not exceed 5 ppmvd (@ 15% O₂ ,
9 dry). Emissions shall be calculated on a 30-day rolling average. This limitation
10 applies to steady state operation, not including startup and shutdown.

11 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
12 CEM consisting of NO_x and O₂ monitors to determine compliance with the NO_x
13 limitation. The CEM shall operate as outlined in IX.H.1.f.
14

15
16 vi. Combustion Turbine Startup / Shutdown Emission Minimization Plan
17

18 A. Startup begins when the fuel valves open and natural gas is supplied to the
19 combustion turbines
20

21 B. Startup ends when either of the following conditions is met:
22

23 I. The NO_x water injection pump is operational, the dilution air temperature is
24 greater than 600°F, the stack inlet temperature reaches 570°F, the ammonia
25 block valve has opened and ammonia is being injected into the SCR and the
26 unit has reached an output of ten (10) gross MW; or
27

28 II. The unit has been in startup for two (2) hours.
29

30 C. Unit shutdown begins when the unit load or output is reduced below ten (10) gross
31 MW with the intent of removing the unit from service.
32

33 D. Shutdown ends at the cessation of fuel input to the turbine combustor.
34

35 E. Periods of startup or shutdown shall not exceed two (2) hours per combustion
36 turbine per day.
37

38 F. Turbine output (turbine load) shall be monitored and recorded on an hourly basis
39 with an electrical meter.

1 k. Tesoro Refining & Marketing Company

2
3 i. Source-wide PM₁₀ Cap

4 No later than January 1, 2019, combined emissions of PM₁₀ shall not exceed 2.25 tons
5 per day (tpd).

6
7 A. Setting of emission factors:

8
9 The emission factors derived from the most current performance test shall be
10 applied to the relevant quantities of fuel combusted. Unless adjusted by
11 performance testing as discussed in IX.H.2.k.i.B below, the default emission factors
12 to be used are as follows:

13
14 Natural gas:

15 Filterable PM₁₀: 0.0019 lb/MMBtu

16 Condensable PM₁₀: 0.0056 lb/MMBtu

17
18 Plant gas:

19 Filterable PM₁₀: 0.0019 lb/MMBtu

20 Condensable PM₁₀: 0.0056 lb/MMBtu

21
22 Fuel Oil: The PM₁₀ emission factor shall be determined from the latest edition of
23 AP-42

24
25 Cooling Towers: The PM₁₀ emission factor shall be determined from the latest
26 edition of AP-42

27
28 FCC Wet Scrubber:

29 The PM₁₀ emission factors shall be based on the most recent stack test and
30 verified by parametric monitoring as outlined in IX.H.1.g.i.B.III

31
32 Where mixtures of fuel are used in a Unit, the above factors shall be
33 weighted according to the use of each fuel.

34
35 B. The default emission factors listed in IX.H.2.k.i.A above apply until such time as
36 stack testing is conducted as outlined below:

37
38 Initial PM₁₀ stack testing on the FCC wet gas scrubber stack shall be conducted no
39 later than January 1, 2019 and at least ~~[once every three (3) years-~~
40 ~~thereafter]~~ annually hereafter. Stack testing shall be performed as outlined in
41 IX.H.1.e.

42
43 Results from any stack testing performed at any other PM₁₀ sources in accordance
44 with IX.H.1.e shall be used where available.

45
46 C. Compliance with the Source-wide PM₁₀ Cap shall be determined for each

1 day as follows:
2

3 Total 24-hour PM₁₀ emissions for the emission points shall be calculated by adding
4 the daily results of the PM₁₀ emissions equations listed below for natural gas, plant
5 gas, and fuel oil combustion. These emissions shall be added to the emissions
6 from the cooling towers and wet scrubber to arrive at a combined daily PM₁₀
7 emission total. For purposes of this subsection a “day” is defined as a period of 24-
8 hours commencing at midnight and ending at the following midnight.
9

10 Daily natural gas and plant gas consumption shall be determined through the
11 use of flow meters.
12

13 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
14 tanks that supply combustion sources.
15

16 The emissions for each emitting unit shall be calculated by multiplying the
17 hours of operation of a unit, feed rate to a unit, or quantity of each fuel
18 combusted at each affected unit by the associated emission factor and
19 summing the results.
20

21 ii. Source-wide NO_x Cap

22 No later than January 1, 2019, combined emissions of NO_x shall not exceed 2.3 tons per
23 day (tpd) and 475 tons per rolling 12-month period.
24

25 A. Setting of emission factors:
26

27 The emission factors derived from the most current performance test shall be
28 applied to the relevant quantities of fuel combusted. Unless adjusted by
29 performance testing as discussed in IX.H.2.k.ii.B below, the default emission
30 factors to be used are as follows:
31

32 Natural gas/refinery fuel gas combustion using: Low NO_x burners (LNB): 0.051
33 lbs/MMbtu

34 Ultra-Low NO_x (ULNB) burners: 0.04 lbs/MMbtu

35 Diesel fuel: shall be determined from the latest edition of AP-42
36

37 B. The default emission factors listed in IX.H.2.k.ii.A above apply until such time as
38 stack testing is conducted as outlined below:
39

40 Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment
41 above 100 MMBtu/hr has already been performed and shall be conducted at least
42 annually following the date of the last test. At that time a new flow-weighted average
43 emission factor in terms of: lbs/MMbtu shall be derived. Stack testing shall be
44 performed as outlined in IX.H.1.e. Stack testing is not required for natural
45 gas/refinery fuel gas combustion equipment with a NO_x CEMS.
46

1 C. Compliance with the source-wide NO_x Cap shall be determined for each
2 day as follows:

3
4 Total 24-hour NO_x emissions shall be calculated by adding the emissions for each
5 emitting unit. The emissions for each emitting unit shall be calculated by
6 multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each
7 fuel combusted at each affected unit by the associated emission factor, and
8 summing the results.

9
10 A NO_x CEM shall be used to calculate daily NO_x emissions from the FCCU wet
11 gas scrubber stack. Emissions shall be determined by multiplying the nitrogen
12 dioxide concentration in the flue gas by the flow rate of the flue gas. The NO_x
13 concentration in the flue gas shall be determined by a CEM as outlined in IX.H.1.f.

14
15 Daily natural gas and plant gas consumption shall be determined through the
16 use of flow meters.

17
18 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
19 tanks that supply combustion sources.

20
21 For purposes of this subsection a “day” is defined as a period of 24-hours
22 commencing at midnight and ending at the following midnight.

23
24 Results shall be tabulated for each day, and records shall be kept which include
25 the meter readings (in the appropriate units) and the calculated emissions.

26
27 iii. Source-wide SO₂ Cap

28 No later than January 1, 2019, combined emissions of SO₂ shall not exceed 3.8 tons per
29 day (tpd) and 300 tons per rolling 12-month period.

30
31 A. Setting of emission factors:

32
33 The emission factors derived from the most current performance test shall be
34 applied to the relevant quantities of fuel combusted. The default emission factors to
35 be used are as follows:

36
37 Natural gas: EF = 0.0006 lb/MMBtu

38 Propane: EF = 0.0006 lb/MMBtu

39 Diesel fuel: shall be determined from the latest edition of AP-42

40
41 Plant fuel gas: the emission factor shall be calculated from the H₂S
42 measurement or from the SO₂ measurement obtained by direct
43 testing/monitoring.

44
45 Where mixtures of fuel are used in a unit, the above factors shall be weighted
46 according to the use of each fuel.

1
2 B. Compliance with the source-wide SO₂ Cap shall be determined for each day as
3 follows: Total daily SO₂ emissions shall be calculated by adding the daily SO₂
4 emissions for natural gas, plant fuel gas, and propane combustion to those from the
5 wet gas scrubber stack, and SRU.

6
7 Daily SO₂ emissions from the FCCU wet gas scrubber stack shall be determined
8 by multiplying the SO₂ concentration in the flue gas by the flow rate of the flue
9 gas. The SO₂ concentration in the flue gas shall be determined by a CEM as
10 outlined in IX.H.1.f.

11
12 SRUs: The emission rate shall be determined by multiplying the sulfur dioxide
13 concentration in the flue gas by the flow rate of the flue gas. The sulfur dioxide
14 concentration in the flue gas shall be determined by CEM as outlined in IX.H.11.f

15
16 Daily SO₂ emissions from other affected units shall be determined by multiplying
17 the quantity of each fuel used daily at each affected unit by the appropriate emission
18 factor.

19
20 Daily natural gas and plant gas consumption shall be determined through the
21 use of flow meters.

22
23 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
24 tanks that supply combustion sources.

25
26 Results shall be tabulated for each day, and records shall be kept which include
27 CEM readings for H₂S (averaged for each one-hour period), all meter reading (in
28 the appropriate units), fuel oil parameters (density and wt% sulfur for each day any
29 fuel oil is burned), and the calculated emissions.

30
31 C. Instead of complying with Condition IX.H.1.g.ii.A, sources may reduce the H₂S
32 content of the refinery plant gas to 60 ppm or less or reduce SO₂ concentration
33 from fuel gas combustion devices to 8 ppmvd at 0% O₂ or less as described in 40
34 CFR 60.102a. Compliance shall be based on a rolling average of 365 days. The
35 owner/operator shall comply with the fuel gas or SO₂ emissions monitoring
36 requirements of 40 CFR 60.107a and the related recordkeeping and reporting
37 requirements of 40 CFR 60.108a. As used herein, refinery "plant gas" shall have
38 the meaning of "fuel gas" as defined in 40 CFR 60.101a, and may be used
39 interchangeably.

40
41 iv. SO₂ emissions from the SRU/TGTU/TGI shall be limited to:

42
43 B. 1.68 tons per day (tpd) for up to 21 days per rolling 12-month period, and

- 1 C. 0.69 tpd for the remainder of the rolling 12-month period.
 2
 3 D. Daily sulfur dioxide emissions from the SRU/TGI/TGTU shall be determined by
 4 multiplying the SO₂ concentration in the flue gas by the mass flow of the flue gas.
 5 The sulfur dioxide concentration in the flue gas shall be determined by CEM as
 6 outlined in IX.H.1.f

7
 8 v. Emergency and Standby Equipment

- 9
 10 A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in
 11 standby or emergency equipment at all times.
 12

- 13 vi. No later than January 1, 2019, the owner/operator shall install the following to control
 14 emissions from the listed equipment:

Emission Unit	Control Equipment
FCCU / CO Boiler	Wet Gas Scrubber, LoTOx
Furnace F-1	Ultra Low NOx Burners
Tanks	Tank Degassing Controls
North and South Flares	Flare Gas Recovery
Furnace H-101	Ultra Low NOx Burners
Truck loading rack	Vapor recovery unit
Sulfur recovery unit	Tail Gas Treatment Unit
API separator	Floating roof (single seal)

15
 16
 17

1 i. University of Utah: University of Utah Facilities

2
3 i. Emissions to the atmosphere from the listed emission points in Building 303 shall
4 not exceed the following concentrations:

5
6
7

Emission Point	Pollutant	ppmdv (3% O ₂ dry)
A. Boiler # [3] 4*	NO _x	187
B. Boilers # [4a] 6 & # [4b] 7.	NO _x	9
C. Boilers # [5a & #5b] 9*.	NO _x	9
D. Turbine	NO _x	9
E. Turbine and WHRU Duct burner	NO _x	15

8
9 *~~[Boiler #4 will be replaced with Boiler #4a and #4b by December 31, 2018]~~By
10 December 31, 2019, Boiler #4 will be decommissioned and Boiler #9 will be
11 installed and operational.

12
13
14 ii. Testing to show compliance with the emissions limitations of Condition i above
15 shall be performed as specified below:

16
17
18
19

Emission Point	Pollutant	Initial Test	Test Frequency
A. Boiler # [3] 4	NO _x	*	every year#
B. Boilers #6 & #7	NO _x	2018	every year#
C. Boilers # [5a & 5b] 9	NO _x	20 [17] <u>20</u>	every year#
D. Turbine	NO _x	*	every year#
E. Turbine and WHRU Duct burner	NO _x	*	every year#

20
21 * Initial tests have been performed and the next method test using EPA approved
22 test methods shall be performed ~~[within 3 years of the last stack test]~~annually.

23
24
25 # A compliance test shall be performed at least once ~~[every three years from the~~
26 ~~date of the last compliance test that demonstrated compliance with the emission-~~
27 ~~limit(s)]~~annually. Compliance testing shall be performed using EPA approved
28 test methods acceptable to the Director. The Director shall be notified, in

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accordance with all applicable rules, of any compliance test that is to be performed. ~~[Beginning January 2018, annual screening with a portable monitor must be conducted in those years that a compliance test is not performed. Screening with a portable monitor shall be performed in accordance with the portable monitor manufacturer's specifications. If screening with a portable monitor indicates a potential exceedance of the concentration limit, a compliance test must be performed within 90 days of that screening. Records shall be kept on site which indicate the date, time, and results of each screening and demonstrate that the portable monitor was operated in accordance with manufacturer's specifications.]~~

~~iii. After January 1, 2019, Boiler #3 shall only be used as a back-up/peaking boiler and shall not exceed 300 hours of operation per rolling 12 months. Boiler #3 may be operated on a continuous basis if it is equipped with low NO_x burners or is replaced with a boiler that has low NO_x burners.]~~

DRAFT

1 m. Utah Municipal Power Association: West Valley Power Plant.
2

3 i. Total emissions of NO_x from all five (5) turbines combined shall be no greater than
4 1050 lb of NO_x on a daily basis. For purposes of this subpart, a "day" is defined as a
5 period of 24- hours commencing at midnight and ending at the following midnight.
6

7 ii. Emissions of NO_x shall not exceed 5ppmdv (@ 15% O₂, dry) on a 30-day rolling
8 average.
9

10 iii. Total emissions of NO_x from all five (5) turbines shall include the sum of all periods in
11 the day including periods of startup, shutdown, and maintenance.
12

13 iv. The NO_x emission rate (lb/hr) shall be determined by CEM. The CEM shall
14 operate as outlined in IX.H.1.f.

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1 ---

2 H.4 Interim Emission Limits and Operating Practices

3
4 a. The terms and conditions of this Subsection IX.H.4 shall apply to the sources listed in this
5 section on a temporary basis, as a bridge between the 1991 PM₁₀ State Implementation Plan and
6 this PM₁₀ Maintenance Plan. For all other point sources listed in IX.H.2 and IX.H.3 the limits
7 apply upon approval by the Utah Air Quality Board of the PM₁₀ Maintenance Plan. These
8 bridge requirements are needed to impose limits on the sources that have time delays for
9 implementation of controls. During this timeframe, the sources listed in this section may not
10 meet the established limits listed in IX.H.1 and IX.H.2. As the control technology for the
11 sources listed in this section is installed and operational, the terms and conditions listed in
12 IX.H.1 and IX.H.2 become applicable and those limits replace the limits in this subsection. In no
13 case, shall the terms and conditions listed in this Subsection IX.H.4 extend beyond January
14 1, 2019.

15
16 b. Petroleum Refineries:

17
18 i. All petroleum refineries in or affecting the PM₁₀ nonattainment/maintenance area shall, for
19 the purpose of this PM₁₀ Maintenance Plan:

20
21 A. Achieve an emission rate equivalent to no more than 9.8 kg of SO₂ per 1,000 kg of
22 coke burn- off from any Catalytic Cracking unit by use of low-SO_x catalyst or
23 equivalent emission reduction techniques or procedures, including those outlined in 40
24 CFR 60, Subpart J. Unless otherwise specified in IX.H.2, compliance shall be
25 determined for each day based on a rolling seven-day average.

26
27 B. Compliance Demonstrations.

28
29 I. Compliance with the maximum daily (24-hr) plant-wide emission limitations for
30 PM₁₀, SO₂, and NO_x shall be determined by adding the calculated emission
31 estimates for all fuel burning process equipment to those from any stack-tested or
32 CEM-measured source components. NO_x and PM₁₀ emission factors shall be
33 determined from AP-42 or from test data.

34 For SO_x, the emission factors are:

35 Natural gas: EF = 0.60 lb/MMscf

36 Propane: EF = 0.60 lb/MMscf

37 Plant gas: the emission factor shall be calculated from the H₂S measurement
38 required in IX.H.1.g.ii.A.

39
40 Fuel oils (when permitted): The emission factor shall be calculated based on the
41 weight percent of sulfur, as determined by ASTM Method D-4294-89 or EPA-
42 approved equivalent, and the density of the fuel oil, as follows:

43
44
$$EF \text{ (lb SO}_2\text{/k gal)} = \text{density (lb/gal)} * (1000 \text{ gal/k gal)} * \text{wt.\% S}/100 * (64 \text{ lb SO}_2\text{/32 lb S)}$$

45
46
47 Where mixtures of fuel are used in an affected unit, the above factors shall be
48 weighted according to the use of each fuel.

1
2
3
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6

II. Daily emission estimates for stack-tested source components shall be made by multiplying the latest stack-tested hourly emission rate times the logged hours of operation (or other relevant parameter) for that source component for each day. This shall not preclude a source from determining emissions through the use of a CEM that meets the requirements of R307-170.

DRAFT

1 c. Big West Oil Company

2 i. PM₁₀ Emissions

3 A. Combined emissions of filterable PM₁₀ from all external combustion process
4 equipment shall not exceed the following:

5
6 I. 0.377 tons per day [~~between October 1 and March 31;~~

7
8 II. ~~0.407 tons per day, between April 1 and September 30].~~

9
10 B. Emissions shall be determined for each day by multiplying the appropriate emission
11 factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation,
12 feed rate, or quantity of fuel combusted) at each affected unit, and summing the
13 results for the group of affected units.

14
15 The daily primary PM₁₀ contribution from the Catalyst Regeneration System
16 shall be calculated using the following equation:

17
18
$$\text{Emitted PM}_{10} = (\text{Feed rate to FCC in kbbbl/time}) * (22 \text{ lbs/kbbbl})$$

19
20 wherein the emission factor (22 lbs/kbbbl) may be re-established by stack testing.
21 Total 24-hour PM₁₀ emissions shall be calculated by adding the daily emissions from
22 the external combustion process equipment to the estimate for the Catalyst
23 Regeneration System.

24
25 ii. SO₂ Emissions

26
27 A. Combined emissions of sulfur dioxide from all external combustion process
28 equipment shall not exceed the following:

29
30 I. 2.764 tons/day [~~between October 1 and March 31;~~

31
32 II. ~~3.639 tons/day, between April 1 and September 30].~~

33
34 B. Emissions shall be determined for each day by multiplying the appropriate emission
35 factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation,
36 feed rate, or quantity of fuel combusted) at each affected unit, and summing the
37 results for the group of affected units.

38
39 The daily SO₂ emission from the Catalyst Regeneration System shall be
40 calculated using the following equation:

41
42
$$\text{SO}_2 = [43.3 \text{ lb SO}_2/\text{hr} / 7,688 \text{ bbl feed/day}] \times [(\text{operational feed rate in bbl/day}) \times$$

43
$$(\text{wt\% sulfur in feed} / 0.1878 \text{ wt\%}) \times (\text{operating hr/day})]$$

1 The FCC feed weight percent sulfur concentration shall be determined by the
2 refinery laboratory every 30 days with one or more analyses. Alternatively, SO₂
3 emissions from the Catalyst Regeneration System may be determined using a
4 Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

5
6 Emissions from the SRU Tail Gas Incinerator (TGI) shall be determined for each
7 day by multiplying the sulfur dioxide concentration in the flue gas by the mass
8 flow of the flue gas.

9
10 Total 24-hour SO₂ emissions shall be calculated by adding the daily emissions from
11 the external combustion process equipment to the values for the Catalyst
12 Regeneration System and the SRU.

13
14 iii. NO_x Emissions

15
16 A. Combined emissions of NO_x from all external combustion process equipment shall
17 not exceed the following:

18
19 I. 1.027 tons per day [~~between October 1 and March 31;~~

20
21 II. ~~1.145 tons per day, between April 1 and September 30].~~

22
23 B. Emissions shall be determined for each day by multiplying the appropriate
24 emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of
25 operation, feed rate, or quantity of fuel combusted) at each affected unit, and
26 summing the results for the group of affected units.

27
28 The daily NO_x emission from the Catalyst Regeneration System shall be calculated
29 using the following equation:

30
31
$$\text{NO}_x = (\text{Flue Gas, moles/hr}) \times (180 \text{ ppm} / 1,000,000) \times (30.006 \text{ lb/mole}) \times (\text{operating}$$

32
$$\text{hr/day})$$

33
34 wherein the scalar value (180 ppm) may be re-established by stack testing.
35 Alternatively, NO_x emissions from the Catalyst Regeneration System may be
36 determined using a Continuous Emissions Monitor (CEM) in accordance
37 with IX.H.1.f.

38
39 Total 24-hour NO_x emissions shall be calculated by adding the daily emissions
40 from gas-fired compressor drivers and the external combustion process equipment
41 to the value for the Catalyst Regeneration System.

1 d. Chevron Products Company

2
3 i. PM₁₀ Emissions

- 4
5 A. Combined emissions of filterable PM₁₀ from all external combustion process
6 equipment shall be no greater than 0.234 tons per day.

7
8 Emissions shall be determined for each day by multiplying the appropriate
9 emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of
10 operation, feed rate, or quantity of fuel combusted) at each affected unit, and
11 summing the results for the group of affected units.

12
13 ii. SO₂ Emissions

- 14
15 A. Combined emissions of sulfur dioxide from gas-fired compressor drivers and all
16 external combustion process equipment, including the FCC CO Boiler and
17 Catalyst Regenerator, shall not exceed 0.5 tons/day.

18
19 Emissions shall be determined for each day by multiplying the appropriate
20 emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of
21 operation, feed rate, or quantity of fuel combusted) at each affected unit, and
22 summing the results for the group of affected units.

23
24 Alternatively, SO₂ emissions from the FCC CO Boiler and Catalyst Regenerator
25 may be determined using a Continuous Emissions Monitor (CEM) in accordance
26 with IX.H.1.f.

27
28 iii. NO_x Emissions

- 29
30 A. Combined emissions of NO_x from gas-fired compressor drivers and all external
31 combustion process equipment, including the FCC CO Boiler and Catalyst
32 Regenerator and the SRU Tail Gas Incinerator, shall be no greater than 2.52 tons
33 per day.

34
35 Emissions shall be determined for each day by multiplying the appropriate
36 emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of
37 operation, feed rate, or quantity of fuel combusted) at each affected unit, and
38 summing the results for the group of affected units.

39
40 Alternatively, NO_x emissions from the FCC CO Boiler and Catalyst Regenerator
41 may be determined using a Continuous Emissions Monitor (CEM) in accordance
42 with IX.H.1.f.

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iv. Chevron shall be permitted to combust HF alkylation polymer oil in its Alkylation unit.

DRAFT

1 e. Holly Refining and Marketing Company

2
3 i. PM₁₀ Emissions

4
5 A. Combined emissions of filterable PM₁₀ from all combustion sources, shall be no
6 greater than 0.44 tons per day.

7
8 Emissions shall be determined for each day by multiplying the appropriate emission
9 factor from section IX.H.4.b.i.B, or from testing as described below, by the relevant
10 parameter (e.g. hours of operation, feed rate, or quantity of fuel combusted) at each
11 affected unit, and summing the results for the group of affected units.

12
13 ii. SO₂ Emissions

14
15 A. Combined emissions of SO₂ from all sources shall be no greater than 4.714 tons per
16 day.

17
18 Emissions shall be determined for each day by multiplying the appropriate emission
19 factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation,
20 feed rate, or quantity of fuel combusted) at each affected unit, and summing the
21 results for the group of affected units.

22
23 Emissions from the FCC wet scrubbers shall be determined using a Continuous
24 Emissions Monitor (CEM) in accordance with IX.H.1.f.

25
26 iii. NO_x Emissions:

27
28 A. Combined emissions of NO_x from all sources shall be no greater than 2.20 tons per
29 day.

30
31 Emissions shall be determined for each day by multiplying the appropriate emission
32 factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation,
33 feed rate, or quantity of fuel combusted) at each affected unit, and summing the
34 results for the group of affected units.

1 f. Tesoro Refining & Marketing Company

2
3 i. PM₁₀ Emissions

- 4
5 A. Combined emissions of filterable PM₁₀ from gas-fired compressor drivers and all
6 external combustion process equipment, including the FCC/CO Boiler (ESP), shall be no
7 greater than 0.261 tons per day.

8
9 Emissions for gas-fired compressor drivers and the group of external combustion
10 process equipment shall be determined for each day by multiplying the appropriate
11 emission factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of
12 operation, feed rate, or quantity of fuel combusted) at each affected unit, and summing
13 the results for the group of affected units.

14
15 ii. SO₂ Emissions

- 16
17 A. Combined emissions of SO₂ from gas-fired compressor drivers and all external
18 combustion process equipment, including the FCC/CO Boiler (ESP), shall not
19 exceed ~~the following:~~

20
21 I. ~~November 1 through end of February:~~ 3.699 tons/day.

22
23 ~~[H. March 1 through October 31: 4.374 tons/day.]~~

24
25 Emissions shall be determined for each day by multiplying the appropriate emission
26 factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation,
27 feed rate, or quantity of fuel combusted) at each affected unit, and summing the
28 results for the group of affected units.

29
30 Emissions from the ESP stack (FCC/CO Boiler) shall be determined by multiplying
31 the SO₂ concentration in the flue gas by the mass flow of the flue gas.

32
33 The SO₂ concentration in the flue gas shall be determined by a continuous
34 emission monitor (CEM).

35
36 iii. NO_x Emissions

- 37
38 A. Combined emissions of NO_x from gas-fired compressor drivers and all external
39 combustion process equipment shall be no greater than 1.988 tons per day.

40
41 Emissions shall be determined for each day by multiplying the appropriate emission
42 factor from section IX.H.4.b.i.B by the relevant parameter (e.g. hours of operation, feed
43 rate, or quantity of fuel combusted) at each affected unit, and summing the results for
44 the group of affected units.

1 **H.11. General Requirements: Control Measures for Area and Point**
2 **Sources, Emission Limits and Operating Practices, PM_{2.5}**

- 3
4 a. Except as otherwise outlined in individual conditions of this Subsection IX.H.11 listed
5 below, the terms and conditions of this Subsection IX.H.11 shall apply to all sources
6 subsequently addressed in Subsection IX.H.12 and 13. Should any inconsistencies exist
7 between these subsections, the source specific conditions listed in IX.H.12 and 13 shall
8 take precedence.
- 9 b. Definitions:
- 10
11 i. The definitions contained in R307-101-2, Definitions, apply to Section IX, Part H.
12
13 ii. Natural gas curtailment means a period of time during which the supply of natural gas
14 to an affected facility is halted for reasons beyond the control of the facility. The act of
15 entering into a contractual agreement with a supplier of natural gas established for
16 curtailment purposes does not constitute a reason that is under the control of a facility
17 for the purposes of this definition. An increase in the cost or unit price of natural gas
18 does not constitute a period of natural gas curtailment.
- 19
20 c. Recordkeeping and Reporting:
- 21
22 i. Any information used to determine compliance shall be recorded for all periods when
23 the source is in operation, and such records shall be kept for a minimum of five years.
24 Any or all of these records shall be made available to the Director upon request.
- 25
26 ii. Each source shall comply with all applicable sections of R307-150 Emission
27 Inventories. iii. Each source shall submit a report of any deviation from the
28 applicable requirements of this Subsection IX.H, including those attributable to upset
29 conditions, the probable cause of such deviations, and any corrective actions or
30 preventive measures taken. The report shall be submitted to the Director no later
31 than 24-months following the deviation or earlier if specified by an underlying
32 applicable requirement. Deviations due to breakdowns shall be reported according to
33 the breakdown provisions of R307-107.
- 34
35 d. Emission Limitations:
- 36
37 i. All emission limitations listed in Subsections IX.H.12 and IX.H.13 apply at all times,
38 unless otherwise specified in the source specific conditions listed in IX.H.12 and 13.
- 39
40 ii. All emission limitations of particulate matter (PM_{2.5}) listed in Subsections
41 IX.H.12 and IX.H.13 include both filterable PM_{2.5} and condensable PM, unless
42 otherwise specified in the source specific conditions listed in IX.H.12 and
43 IX.H.13.
- 44
45 e. Stack Testing:

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- i. As applicable, stack testing to show compliance with the emission limitations for the sources in Subsection IX.H.12 and 13 shall be performed in accordance with the following:
 - A. Sample Location: The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other EPA-approved testing methods acceptable to the Director. Occupational Safety and Health Administration (OSHA) approvable access shall be provided to the test location.
 - B. Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2 or EPA Test Method No. 19 "SO₂ Removal & PM, SO₂, NO_x Rates from Electric Utility Steam Generators" or other EPA-approved testing methods acceptable to the Director.
 - C. PM: 40 CFR 60, Appendix A, Method 5, or other EPA approved testing methods acceptable to the Director.
 - D. PM_{2.5}: 40 CFR 51, Appendix M, 201a and 202, or other EPA approved testing methods acceptable to the Director. The back half condensables shall be used for compliance demonstration as well as for inventory purposes. If a method other than 201a is used, the portion of the front half of the catch considered PM_{2.5} shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.
 - E. SO₂: 40 CFR 60 Appendix A, Method 6C, or other EPA-approved testing methods acceptable to the Director.
 - F. NO_x: 40 CFR 60 Appendix A, Method 7E, or other EPA-approved testing methods acceptable to the Director.
 - G. VOC: 40 CFR 60 Appendix A, Method 25A or other EPA-approved testing methods acceptable to the Director.
 - H. Calculations: To determine mass emission rates (lb/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 to give the results in the specified units of the emission limitation.
 - I. A stack test protocol shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by the Director.
 - J. The production rate during all compliance testing shall be no less than 90% of the maximum production rate achieved in the previous three (3) years. If the desired production rate is not achieved at the time of the test, the maximum production rate

1 shall be 110% of the tested achieved rate, but not more than the maximum allowable
2 production rate. This new allowable maximum production rate shall remain in effect
3 until successfully tested at a higher rate. The owner/operator shall request a higher
4 production rate when necessary. Testing at no less than 90% of the higher rate shall
5 be conducted. A new maximum production rate (110% of the new rate) will then be
6 allowed if the test is successful. This process may be repeated until the maximum
7 allowable production rate is achieved.

8
9 f. Continuous Emission and Opacity Monitoring

10
11 i. For all continuous monitoring devices, the following shall apply:

12
13 A. Except for system breakdown, repairs, calibration checks, and zero and span
14 adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an
15 affected source shall continuously operate all required continuous monitoring
16 systems and shall meet minimum frequency of operation requirements as outlined
17 in R307-170 and 40 CFR 60.13. Flow measurement shall be in accordance with the
18 requirements of 40 CFR 52, Appendix E; 40 CFR 60 Appendix B; or 40 CFR 75,
19 Appendix A.

20
21 B. The monitoring system shall comply with all applicable sections of R307-170; 40
22 CFR 13; and 40 CFR 60, Appendix B – Performance Specifications.

23
24 ii. Opacity observations of emissions from stationary sources shall be conducted in
25 accordance with 40 CFR 60, Appendix A, Method 9.

26
27 g. Petroleum Refineries.

28
29 i. Limits at Fluid Catalytic Cracking Units

30
31 A. FCCU SO₂ Emissions

32
33 I. Each owner or operator of an FCCU shall comply with an SO₂ emission limit
34 of 25 ppmvd @ 0% excess air on a 365-day rolling average basis and 50
35 ppmvd @ 0% excess air on a 7-day rolling average basis.

36
37 II. Compliance with this limit shall be determined by following 40 C.F.R.
38 §60.105a(g).

39
40 B. FCCU PM Emissions

41
42 I. Each owner or operator of an FCCU shall comply with an emission limit of 1.0
43 pounds PM per 1000 pounds coke burn-off.

44
45 II. Compliance with this limit shall be determined by following the stack test
46 protocol specified in 40 C.F.R. §60.106(b) to measure PM emissions on the

1 FCCU. Each owner operator shall conduct stack tests [~~once every [five]three~~
2 ~~years-]annually~~ at each FCCU.
3

4 III. No later than January 1, 2019, each owner or operator of an FCCU shall install,
5 operate and maintain a continuous parameter monitor system (CPMS) to
6 measure and record operating parameters for determination of source-wide
7 PM_{2.5} emissions as per the requirements of 40 CFR 60.105a(b)(1).
8

9 ii. Limits on Refinery Fuel Gas
10

11 A. All petroleum refineries in or affecting any PM_{2.5} nonattainment area or any PM₁₀
12 nonattainment or maintenance area shall reduce the H₂S content of the refinery plant
13 gas to 60 ppm or less as described in 40 CFR 60.102a. Compliance shall be based
14 on a rolling average of 365 days. The owner/operator shall comply with the fuel gas
15 monitoring requirements of 40 CFR 60.107a and the related recordkeeping and
16 reporting requirements of 40 CFR 60.108a. As used herein, refinery “plant gas”
17 shall have the meaning of “fuel gas” as defined in 40 CFR 60.101a, and may be
18 used interchangeably.
19

20 B. For natural gas, compliance is assumed while the fuel comes from a public utility.
21

22 iii. Limits on Heat Exchangers
23

24 A. Each owner or operator shall comply with the requirements of 40 CFR 63.654
25 for heat exchange systems in VOC service. The owner or operator may elect to
26 use another EPA-approved method other than the Modified El Paso Method if
27 approved by the Director.
28

29 I. The following applies in lieu of 40 CFR 63.654(b): A heat exchange system is
30 exempt from the requirements in paragraphs 63.654(c) through (g) of this
31 section if it meets any one of the criteria in the following paragraphs (1)
32 through (2) of this section.
33

34 1. All heat exchangers that are in VOC service within the heat exchange
35 system that either:
36

37 a. Operate with the minimum pressure on the cooling water side at
38 least 35 kilopascals greater than the maximum pressure on the
39 process side; or
40

41 b. Employ an intervening cooling fluid, containing less than 10 percent by
42 weight of VOCs, between the process and the cooling water. This
43 intervening fluid must serve to isolate the cooling water from the process
44 fluid and must not be sent through a cooling tower or discharged. For
45 purposes of this section, discharge does not include emptying for
46 maintenance purposes.

1
2 2. The heat exchange system cools process fluids that contain less than 10
3 percent by weight VOCs (i.e., the heat exchange system does not contain
4 any heat exchangers that are in VOC service).
5

6 iv. Leak Detection and Repair Requirements
7

8 A. Each owner or operator shall comply with the requirements of 40 CFR 60.590a to
9 60.593a as soon as practicable.
10

11 B. For units complying with the Sustainable Skip Period, previous process unit
12 monitoring results may be used to determine the initial skip period interval
13 provided that each valve has been monitored using the 500 ppm leak definition.
14

15 v. Requirements on Hydrocarbon Flares
16

17 A. All hydrocarbon flares at petroleum refineries located in or affecting a PM_{2.5}
18 nonattainment area or any PM₁₀ nonattainment or maintenance area shall be
19 subject to the flaring requirements of NSPS Subpart Ja (40 CFR 60.100a–109a), if
20 not already subject under the flare applicability provisions of Ja.
21

22 B. No later than January 1, 2019, all major source petroleum refineries in or affecting
23 any PM_{2.5} nonattainment area or any PM₁₀ nonattainment or maintenance area
24 shall either 1) install and operate a flare gas recovery system designed to limit
25 hydrocarbon flaring produced from each affected flare during normal operations to
26 levels below the values listed in 40 CFR 60.103a(c), or 2) limit flaring during
27 normal operations to 500,000 scfd for each affected flare. Flare gas recovery is not
28 required for dedicated SRU flare and header systems, or HF flare and header
29 systems.
30

31 vi. Requirements on Tank Degassing
32

33 A. Beginning January 1, 2017, the owner or operator of any stationary tank of 40,000-
34 gallon or greater capacity and containing or last containing any organic liquid, with
35 a true vapor pressure equal or greater than 10.5 kPa (1.52 psia) at storage
36 temperature (see R307-324-4(1)) shall not allow it to be opened to the atmosphere
37 unless the emissions are controlled by exhausting VOCs contained in the tank
38 vapor-space to a vapor control device until the organic vapor concentration is 10
39 percent or less of the lower explosion limit (LEL).
40

41 B. These degassing provisions shall not apply while connecting or disconnecting
42 degassing equipment.
43

44 C. The Director shall be notified of the intent to degas any tank subject to the rule.
45 Except in an emergency situation, initial notification shall be submitted at least

1 three (3) days prior to degassing operations. The initial notification shall include:

2
3 I. Start date and time;

4
5 II. Tank owner, address, tank location, and applicable tank permit numbers;

6
7 III. Degassing operator's name, contact person, telephone number;

8
9 IV. Tank capacity, volume of space to be degassed, and materials stored;

10
11 V. Description of vapor control device.

12
13 vii. No Burning of Liquid Fuel Oil in Stationary Sources

14
15 A. No petroleum refineries in or affecting any $PM_{2.5}$ nonattainment area or PM_{10}
16 nonattainment or maintenance area shall be allowed to burn liquid fuel oil in
17 stationary sources except during natural gas curtailments or as specified in the
18 individual subsections of Section IX, Part H.

19
20 B. The use of diesel fuel meeting the specifications of 40 CFR 80.510 in standby or
21 emergency equipment is exempt from the limitation of IX.H.11.g.vii.A above.

22
23 h. Catalytic Oxidation for VOC Control

24
25 i. Internal Combustion Engines

26
27 A. Emissions from each VOC catalytic-controlled IC engine shall be routed through the
28 oxidation catalyst system prior to being emitted to the atmosphere. The oxidation
29 catalyst system shall be installed and operated as outlined in 40 CFR 63.6625(e).

30
31 ii. Natural Gas Combustion Turbines

32
33 A. Emissions from each VOC catalytic-controlled combustion turbine shall be routed
34 through the oxidation catalyst system prior to being emitted to the atmosphere. The
35 oxidation catalyst system shall be installed and operated according to the
36 manufacturer's emission-related written instructions and in a manner consistent with
37 good air pollution control practice for minimizing emissions.

1 **H.12. Source-Specific Emission Limitations in Salt Lake City – UT PM_{2.5}**
2 **Nonattainment Area**

3
4 a. ATK Launch Systems Inc. Promontory

5
6 i. During the period~~[-November 1 to February 28/29 on days]~~ when the 24-hour average
7 PM2.5 levels exceed 35 µg/m³ at the nearest real-time monitoring station, the open
8 burning of reactive wastes with properties identified in 40 CFR 261.23 (a) (6) (7) (8)
9 may be conducted~~[-when the 24-hour average PM_{2.5} levels exceed 35 µg/m³ at the~~
10 ~~nearest real-time monitoring station]~~ in limited quantities. Limited quantities, as
11 authorized in the facility’s RCRA Subpart X permit, of time sensitive reactive wastes~~[-~~
12 ~~may be open-burned when the 24-hour average PM_{2.5} levels exceed 35 µg/m³ at the~~
13 ~~nearest real-time monitoring station]~~.

14
15 ii. During~~[-the period November 1 to February 28/29, on]~~ days when the 24-hour average
16 PM2.5 levels exceed 35 µg/m³ at the nearest real-time monitoring station, the following
17 shall not be tested:

18
19 A. Propellant, energetics, pyrotechnics, flares and other reactive compounds greater
20 than 2,400 lbs. per day; or

21
22 B. Rocket motors less than 1,000,000 lbs. of propellant per motor subject to the
23 following exception:

24
25 I. A single test of rocket motors less than 1,000,000 lbs. of propellant per motor is
26 allowed on a day when the 24-hour average PM2.5 level exceeds 35 µg/m³ at
27 the nearest real-time monitoring station provided notice is given to the Director
28 of the Utah Air Quality Division. No additional tests of rocket motors less than
29 1,000,000 lbs. of propellant may be conducted during the inversion period until
30 the 24-hour average PM2.5 level has returned to a concentration below 35
31 µg/m³ at the nearest real-time monitoring station.

32
33 C. During this period, records will be maintained identifying the size of the rocket
34 motors tested and the 24-hour average PM2.5 level at the nearest real-time
35 monitoring station on days when motor testing occur.

36
37 iii. Natural Gas-Fired Boilers

38
39 A. Building M-576

40
41 I. One 71 MMBTU/hr boiler shall be upgraded with low NOx burners and flue gas
42 recirculation by January 2016. The boiler shall be rated at a maximum of 9 ppm.
43 The remaining boiler shall not consume more than 100,000 MCF of natural gas
44 per rolling 12- month period unless upgraded so the NOx emission rate is no
45 greater than 30 ppm.

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II. ~~[Records shall be kept on site which indicate the date, and time of startup and shutdown.]~~ Emission to the atmosphere from the Cleaver Brooks 71 MMBTU/hr boiler inbuilding M-576 shall not exceed the following concentration:

- a. Pollutant _____ ppmvd (3% O₂ dry)
NO_x _____ 9
- b. Compliance with the above emission limits shall be determined by stack test as outlined in Section IX Part H.11.e of this SIP.
- c. Subsequent to initial compliance testing, stack testing is required annually.

B. Building M-14

I. The two 25 MMBTU/hr boiler shall be upgraded with low NO_x burners and flue gas recirculation by December 31, 2024. The boiler shall be rated at a maximum of 9 ppm.

II. Emission to the atmosphere from the two (2) Cleaver Brooks 25 MMBTU/hr boiler inbuilding M-14 shall not exceed the following concentration:

- a. Pollutant _____ ppmvd (3% O₂ dry)
NO_x _____ 9
- b. Compliance with the above emission limits shall be determined by stack test as outlined in Section IX Part H.11.e of this SIP.
- c. Subsequent to initial compliance testing, stack testing is required annually.

1 b. Big West Oil Refinery

2
3 i. Source-wide PM_{2.5}:

4 Following installation of the Flue Gas Blow Back Filter (FGF), but no later than
5 January 1, 2019, combined emissions of PM_{2.5} (filterable+condensable) shall not
6 exceed 0.29 tons per day and 72.5 tons per rolling 12-month period. No later than
7 January 1, 2019, Big West Oil shall conduct stack testing to establish the ratio of
8 filterable and condensable PM_{2.5} from the Catalyst Regeneration System.

9
10 A. Setting of emission factors:

11
12 The emission factors derived from the most current performance test shall be
13 applied to the relevant quantities of fuel combusted. Unless adjusted by
14 performance testing as discussed in IX.H.12.b.i.B below, the default emission
15 factors to be used are as follows:

16
17 Natural gas:

18 Filterable PM_{2.5}: 1.9 lb/MMscf

19 Condensable PM_{2.5}: 5.7 lb/MMscf

20
21 Plant gas:

22 Filterable PM_{2.5}: 1.9 lb/MMscf

23 Condensable PM_{2.5}: 5.7 lb/MMscf

24
25 Fuel Oil: The PM_{2.5} emission factors shall be determined from the latest edition
26 of AP-42

27
28 FCC Stacks: The PM_{2.5} emission factors shall be established by stack test.

29
30 Where mixtures of fuel are used in a Unit, the above factors shall be weighted
31 according to the use of each fuel.

32
33 B. The default emission factors for the FCC listed in IX.H.12.b.i.A above apply
34 until such time as stack testing is conducted as outlined below:

35
36 PM_{2.5} stack testing on the FCC shall be performed initially no later than
37 January 1, 2019 and at least ~~once every three (3) years~~ annually thereafter.
38 Stack testing shall be performed as outlined in IX.H.11.e.

39
40 C. Compliance with the source-wide PM_{2.5} Cap shall be determined for each day
41 as follows: Total 24-hour PM_{2.5} emissions for the emission points shall be
42 calculated by adding the daily results of the PM_{2.5} emissions equations listed
43 below for natural gas, plant gas, and fuel oil combustion. These emissions shall
44 be added to the emissions from the FCC to arrive at a combined daily PM_{2.5}
45 emission total.

1
2 For purposes of this subsection a “day” is defined as a period of 24-hours
3 commencing at midnight and ending at the following midnight.
4

5 Daily gas consumption shall be measured by meters that can delineate the
6 flow of gas to the boilers, furnaces and the SRU incinerator.
7

8 The equation used to determine emissions from these units shall be as
9 follows: Emissions = Emission Factor (lb/MMscf) * Gas Consumption
10 (MMscf/24 hrs)/(2,000
11 lb/ton)
12

13 Daily fuel oil consumption shall be monitored by means of leveling gauges
14 on all tanks that supply combustion sources.
15

16 The daily PM_{2.5} emissions from the FCC shall be calculated using the following
17 equation: E = FR * EF
18

19 Where:

20 E = Emitted PM_{2.5}

21 FR = Feed Rate to Unit (kbbbls/day)

22 EF = emission factor (lbs/kbbl), established by the most recent stack test
23

24 Results shall be tabulated for each day, and records shall be kept which include
25 the meter readings (in the appropriate units) and the calculated emissions.
26

27 ii. Source-wide NO_x Cap

28 No later than January 1, 2019, combined emissions of NO_x shall not exceed 0.80 tons
29 per day (tpd) and 195 tons per rolling 12-month period.
30

31 A. Setting of emission factors:
32

33 The emission factors derived from the most current performance test shall be applied
34 to the relevant quantities of fuel combusted. Unless adjusted by performance testing
35 as discussed in IX.H.12.b.ii.B below, the default emission factors to be used are as
36 follows:
37

38 Natural gas: shall be determined from the latest edition of AP-42

39 Plant gas: assumed equal to natural gas

40 Diesel fuel: shall be determined from the latest edition of AP-42
41

42 Where mixtures of fuel are used in a Unit, the above factors shall be weighted
43 according to the use of each fuel.
44

45 B. The default emission factors for the FCC listed in IX.H.12.b.ii.A above apply until

1 such time as stack testing is conducted as outlined below:

2
3 Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment
4 above 40 MMBtu/hr has been performed NO_x emissions for the FCC are monitored
5 with a continuous emission monitoring system. Refinery Boilers and heaters over 40
6 MMBtu/hr, but less than 100 MMBtu/hr, are in compliance with monitoring and work
7 practice standards of Subpart DDDD of Part 63.

- 8
9 C. Compliance with the source-wide NO_x Cap shall be determined for each day as
10 follows: Total 24-hour NO_x emissions shall be calculated by adding the emissions
11 for each emitting unit. The emissions for each emitting unit shall be calculated by
12 multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each
13 fuel combusted at each affected unit by the associated emission factor, and
14 summing the results.

15
16 Daily plant gas consumption at the furnaces, boilers and SRU incinerator shall be
17 measured by flow meters. The equations used to determine emissions shall be as
18 follows:

19
20
$$\text{NO}_x = \text{Emission Factor (lb/MMscf)} * \text{Gas Consumption (MMscf/24 hrs)} / (2,000$$

21 lb/ton)

22
23 Where the emission factor is derived from the fuel used, as listed in IX.H.12.b.ii.A
24 above Daily fuel oil consumption shall be monitored by means of leveling gauges
25 on all tanks that supply combustion sources.

26
27 The daily NO_x emissions from the FCC shall be calculated using a CEM as outlined
28 in IX.H.11.f

29
30 Total daily NO_x emissions shall be calculated by adding the results of the above NO_x
31 equations for natural gas and plant gas combustion to the estimate for the FCC.

32
33 For purposes of this subsection a “day” is defined as a period of 24-hours
34 commencing at midnight and ending at the following midnight.

35
36 Results shall be tabulated for each day, and records shall be kept which include the
37 meter readings (in the appropriate units) and the calculated emissions.

38
39 iii. Source-wide SO₂ Cap

40 No later than January 1, 2019, combined emissions of SO₂ shall not exceed 0.60 tons per
41 day and 140 tons per rolling 12-month period.

42
43 A. Setting of emission factors:

44 The emission factors derived from the most current performance test shall be
45 applied to the relevant quantities of fuel combusted. The default emission factors

1 to be used are as follows:

2
3 Natural Gas - 0.60 lb SO₂/MMscf gas

4
5 Plant Gas: The emission factor to be used in conjunction with plant gas combustion
6 shall be determined through the use of a CEM as outlined in IX.H.11.f.

7
8 SRUs: The emission rate shall be determined by multiplying the sulfur
9 dioxide concentration in the flue gas by the flow rate of the flue gas. The
10 sulfur dioxide concentration in the flue gas shall be determined by CEM as
11 outlined in IX.H.11.f.

12
13 Fuel oil: The emission factor to be used for combustion shall be calculated based
14 on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or
15 EPA approved equivalent acceptable to the Director, and the density of the fuel
16 oil, as follows:

17
18
$$\text{EF (lb SO}_2\text{/k gal)} = \text{density (lb/gal)} * (1000 \text{ gal/k gal)} * \text{wt. \% S}/100 * (64 \text{ lb SO}_2\text{/32}$$

19 lbs)

20
21 Where mixtures of fuel are used in a Unit, the above factors shall be weighted
22 according to the use of each fuel.

23
24 B. Compliance with the source-wide SO₂ Cap shall be determined for each day as
25 follows:

26 Total daily SO₂ emissions shall be calculated by adding the daily SO₂ emissions
27 for natural gas and plant fuel gas combustion, to those from the FCC and SRU
28 stacks.

29
30 The daily SO_x emissions from the FCC shall be calculated using a CEM as outlined
31 in IX.H.11.f

32
33 Daily natural gas and plant gas consumption shall be determined through the use
34 of flow meters.

35
36 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
37 tanks that supply combustion sources.

38
39 For purposes of this subsection a “day” is defined as a period of 24-hours
40 commencing at midnight and ending at the following midnight.

41
42 Results shall be tabulated for each day, and records shall be kept which include
43 CEM readings for H₂S (averaged for each day), all meter readings (in the
44 appropriate units), fuel oil parameters (density and wt% sulfur for each day any
45 fuel oil is burned), and the calculated emissions.

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iv. Emergency and Standby Equipment

A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in standby or emergency equipment at all times.

v. Alternate Startup and Shutdown Requirements

A. During any day which includes startup or shutdown of the FCCU, combined emissions of SO₂ shall not exceed 1.2 tons per day (tpd). For purposes of this subsection, a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

B. The total number of days which include startup or shutdown of the FCCU shall not exceed ten (10) per 12-month rolling period.

vi. Requirements on Hydrocarbon Flares

A. No later than January 1, 2021, routine flaring will be limited to 300,000 scfd for each affected flare ~~[- from October 1 through March 31 and 500,000 scfd for each affected flare for the balance of the year].~~

vii. No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:

Emission Unit	Control Equipment
FCCU Regenerator	Flue gas blowback "Pall Filter", quaternary cyclones with fabric filter
H-404 #1 Crude Heater	Ultra-low NO _x burners
Refinery Flares	Subpart Ja, and MACT CC flaring standards
SRU	Tail gas incinerator and redundant caustic scrubber
Product Loading Racks	Vapor recovery and vapor combustors
Wastewater Treatment System	API separator fixed cover, carbon adsorber canisters to be installed 2019.

1 c. Chemical Lime Company (LHoist North America)

2
3 Lime Production Kiln

- 4
- 5 i. No later than January 1, 2019, or upon source start-up, whichever comes later, SNCR
- 6 technology shall be installed on the Lime Production Kiln.
- 7
- 8 a. Effective January 1, 2019, or upon source start-up, whichever comes later, NO_x
- 9 emissions shall not exceed 56 lb/hr. (3-hr rolling average)
- 10
- 11 b. Compliance with the above emissions limit shall be determined by stack
- 12 testing as outlined in Section IX Part H.11.e of this SIP.
- 13
- 14 ii. No later than January 1, 2019, or upon source start-up, whichever comes later, a
- 15 baghouse control technology shall be installed and operating on the Lime Production
- 16 Kiln.
- 17
- 18 a. Effective January 1, 2019, or upon source start-up, whichever comes later, PM
- 19 emissions shall not exceed 0.12 pounds per ton (lb/ton) of stone feed. (3-hr rolling
- 20 average)
- 21
- 22 b. Effective January 1, 2019, or upon source start-up, whichever comes later, PM_{2.5}
- 23 (filterable + condensable) emissions shall not exceed 1.5 lbs/ton of stone feed. (3-hr
- 24 rolling average)
- 25
- 26 c. Compliance with the above emission limits shall be determined by stack testing as
- 27 outlined in Section IX Part H.11.e of this SIP and in accordance with 40 CFR 63
- 28 Subpart AAAAA.
- 29
- 30 iii. An initial compliance test is required no later than January 1, 2019 (if start-up occurs
- 31 on or before January 1, 2019) or within 180 days of source start-up (if start-up occurs
- 32 after January 1, 2019) ***All subsequent compliance testing shall be performed at least***
- 33 ***once annually based upon the date of the last compliance test.***
- 34
- 35 iv. Upon plant start-up kiln emissions shall be exhausted through the baghouse during all
- 36 startup, shutdown, and operations of the kiln.
- 37
- 38 v. Start-up/shut-down provisions for SNCR technology be as follows:
- 39
- 40
- 41 a. No ammonia or urea injection during startup until the combustion gases exiting
- 42 the kiln reach the temperature when NO_x reduction is effective, and
- 43
- 44 b. No ammonia or urea injection during shutdown.
- 45
- 46 c. Records of ammonia or urea injection shall be documented in an operations log.

- 1 The operations log shall include all periods of start-up/shut-down and subsequent
- 2 beginning and ending times of ammonia or urea injection which documents v.a
- 3 and v.b above.

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1 d. Chevron Products Company - Salt Lake Refinery

2
3 i. Source-wide PM_{2.5} Cap

4
5 No later than January 1, 2019, combined emissions of PM_{2.5} (filterable+condensable)
6 shall not exceed 0.305 tons per day (tpd) and 110 tons per rolling 12-month period.

7
8 A. Setting of emission factors:

9 The emission factors derived from the most current performance test shall be
10 applied to the relevant quantities of fuel combusted. Unless adjusted by
11 performance testing as discussed in IX.H.12.f.i.B below, the default emission
12 factors to be used are as follows:

13
14 Natural gas:

15 Filterable PM_{2.5}: 1.9 lb/MMscf

16 Condensable PM_{2.5}: 5.7 lb/MMscf

17
18 Plant gas:

19 Filterable PM_{2.5}: 1.9 lb/MMscf

20 Condensable PM_{2.5}: 5.7 lb/MMscf

21
22 HF alkylation polymer: shall be determined from the latest edition of AP-42 (HF
23 alkylation polymer treated as fuel oil #6)

24
25 Diesel fuel: shall be determined from the latest edition of AP-42

26
27 FCC Stack:

28 The PM_{2.5} emission factors shall be based on the most recent stack test and verified
29 by parametric monitoring as outlined in IX.H.11.g.i.B.III

30
31 Where mixtures of fuel are used in a Unit, the above factors shall be weighted
32 according to the use of each fuel.

33
34 B. The default emission factors listed in IX.H.12.f.i.A above apply until such time as
35 stack testing is conducted as outlined below:

36
37 Initial PM_{2.5} stack testing on the FCC stack has been performed and shall be
38 conducted at least ~~once every three (3) years from the date of the last stack~~
39 ~~test]annually~~. Stack testing shall be performed as outlined in IX.H.11.e.

40
41 C. Compliance with the source-wide PM_{2.5} Cap shall be determined for each day as
42 follows:

43
44 Total 24-hour PM_{2.5} emissions for the emission points shall be calculated by adding
45 the daily results of the PM_{2.5} emissions equations listed below for natural gas, plant

1 gas, and fuel oil combustion. These emissions shall be added to the emissions from
2 the FCC to arrive at a combined daily PM_{2.5} emission total.

3
4 For purposes of this subsection a “day” is defined as a period of 24-hours
5 commencing at midnight and ending at the following midnight.

6
7 Daily natural gas and plant gas consumption shall be determined through the use of
8 flow meters.

9
10 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
11 tanks that supply combustion sources.

12
13 The equation used to determine emissions for the boilers and furnaces shall be as
14 follows: Emissions = Emission Factor (lb/MMscf) * Gas Consumption (MMscf/24
15 hrs)/(2,000 lb/ton)

16
17 Results shall be tabulated for each day, and records shall be kept which include the
18 meter readings (in the appropriate units) and the calculated emissions.

19
20 ii. Source-wide NO_x Cap

21
22 No later than January 1, 2019, combined emissions of NO_x shall not exceed 2.1 tons per
23 day (tpd) and 766.5 tons per rolling 12-month period.

24
25 A. Setting of emission factors:

26
27 The emission factors derived from the most current performance test shall be
28 applied to the relevant quantities of fuel combusted. Unless adjusted by
29 performance testing as discussed in IX.H.12.f.ii.B below, the default emission
30 factors to be used are as follows:

31
32 Natural gas: shall be determined from the latest edition of AP-42

33
34 Plant gas: assumed equal to natural gas

35
36 Alkylation polymer: shall be determined from the latest edition of AP-42 (as fuel
37 oil #6)

38
39 Diesel fuel: shall be determined from the latest edition of AP-42

40
41 Where mixtures of fuel are used in a Unit, the above factors shall be weighted
42 according to the use of each fuel.

43
44 B. The default emission factors listed in IX.H.12.f.ii.A above apply until such time as
45 stack testing is conducted as outlined below:

1
2 Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment
3 above 100 MMBtu/hr has been performed and shall be conducted at least [~~once~~
4 ~~every three (3) years from the date of the last stack test~~ annually]. At that time a new
5 flow-weighted average emission factor in terms of: lbs/MMBtu shall be derived for
6 each combustion type listed in IX.H.12.f.ii.A above. Stack testing shall be
7 performed as outlined in IX.H.11.e.
8

9 C. Compliance with the source-wide NO_x Cap shall be determined for each day as
10 follows:
11

12 Total 24-hour NO_x emissions shall be calculated by adding the emissions for each
13 emitting unit. The emissions for each emitting unit shall be calculated by
14 multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each
15 fuel combusted at each affected unit by the associated emission factor, and
16 summing the results.
17

18 A NO_x CEM shall be used to calculate daily NO_x emissions from the FCC.
19 Emissions shall be determined by multiplying the nitrogen dioxide concentration in
20 the flue gas by the flow rate of the flue gas. The NO_x concentration in the flue gas
21 shall be determined by a CEM as outlined in IX.H.11.f.
22

23 For purposes of this subsection a “day” is defined as a period of 24-hours
24 commencing at midnight and ending at the following midnight.
25

26 Daily natural gas and plant gas consumption shall be determined through the use of
27 flow meters.
28

29 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
30 tanks that supply combustion sources.
31

32 Results shall be tabulated for each day, and records shall be kept which include the
33 meter readings (in the appropriate units) and the calculated emissions
34

35 iii. Source-wide SO₂
36

37 No later than January 1, 2019, combined emissions of SO₂ shall not exceed 1.05 tons
38 per day (tpd) and 383.3 tons per rolling 12-month period.
39

40 A. Setting of emission factors:
41

42 The emission factors derived from the most current performance test shall be
43 applied to the relevant quantities of fuel combusted. The default emission factors to
44 be used are as follows:
45

1 FCC: The emission rate shall be determined by the FCC SO₂ CEM as outlined in
2 IX.H.11.f.

3
4 SRUs: The emission rate shall be determined by multiplying the sulfur dioxide
5 concentration in the flue gas by the flow rate of the flue gas. The sulfur dioxide
6 concentration in the flue gas shall be determined by CEM as outlined in IX.H.11.f.

7
8 Natural gas: EF = 0.60 lb/MMscf

9
10 Fuel oil & HF Alkylation polymer: The emission factor to be used for combustion
11 shall be calculated based on the weight percent of sulfur, as determined by ASTM
12 Method D-4294-89 or EPA-approved equivalent acceptable to the Director, and the
13 density of the fuel oil, as follows:

14
15
$$\text{EF (lb SO}_2\text{/k gal)} = \text{density (lb/gal)} * (1000 \text{ gal/k gal}) * \text{wt.\% S}/100 * (64 \text{ lb SO}_2\text{/32}$$

16
$$\text{lb S)}$$

17
18 Plant gas: the emission factor shall be calculated from the H₂S measurement
19 obtained from the H₂S CEM.

20
21 Where mixtures of fuel are used in a Unit, the above factors shall be weighted
22 according to the use of each fuel.

23
24 B. Compliance with the source-wide SO₂ Cap shall be determined for each day as
25 follows: Total daily SO₂ emissions shall be calculated by adding the daily SO₂
26 emissions for natural gas and plant fuel gas combustion, to those from the FCC and
27 SRU stacks.

28
29 Daily natural gas and plant gas consumption shall be determined through the use of
30 flow meters.

31
32 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
33 tanks that supply combustion sources.

34
35 Results shall be tabulated for each day, and records shall be kept which include
36 CEM readings for H₂S (averaged for each one-hour period), all meter reading (in
37 the appropriate units), fuel oil parameters (density and wt% sulfur for each day any
38 fuel oil is burned), and the calculated emissions.

39
40 iv. Emergency and Standby Equipment and Alternative Fuels

41
42 A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in
43 standby or emergency equipment at all times.

44
45 B. HF alkylation polymer may be burned in the Alky Furnace (F-36017).

1
2 C. Plant coke may be burned in the FCC Catalyst Regenerator.
3

4 v. Compressor Engine Requirements

5
6 A. Emissions of NO_x from each rich-burn compressor engine shall not exceed the
7 following:
8

Engine Number	NO _x in ppmvd @ 0% O ₂
K35001	236
K35002	208
K35003	230

9 B. Initial stack testing to demonstrate compliance with the above emission limitations
10 shall be performed no later than January 1, 2019 and at least ~~[once every three~~
11 ~~years thereafter]~~annually. Stack testing shall be performed as outlined in IX.H.11.e.
12

13 vi. Flare Calculation

14
15 A. Chevron's Flare #3 receives gases from its Isomerization unit, Reformer unit as
16 well as its HF Alkylation Unit. The HF Alkylation Unit's flow contribution to
17 Flare #3 will not be included in determining compliance with the flow restrictions
18 set in IX.H.11.g.v.B

19 18)

20 vii. No later than January 1, 2019, the owner/operator shall install the following to control
21 emissions from the listed equipment:

Emission Unit	Control Equipment
Boilers: 5, 6, 7	Low NOx burners and flue gas recirculation (FGR)
Cooling Water Towers	High efficiency drift eliminators
Crude Furnaces F21001, F21002	Low NOx burners
Crude Oil Loading	Vapor Combustion Unit (VCU)
FCC Regenerator Stack	Vacuum gas oil hydrotreater, Electrostatic precipitator (ESP) and cyclones
Flares: Flare 1, 2, 3	Flare gas recovery system
HDS Furnaces F64010, F64011	Low NOx burners
Reformer Compressor Drivers K35001, K35002, K35003	Selective Catalytic Reduction (SCR)
Sulfur Recovery Unit 1	Tail gas treatment unit and tail gas incineration
Sulfur Recovery Unit 2	Tail gas treatment unit and tail gas incineration
Wastewater Treatment Plant	Existing wastewater controls system of induced air flotation (IAF) and regenerative thermal oxidation (RTO)

1 e. Compass Minerals Ogden Inc.

2
3 i. NO_x emissions to the atmosphere from the indicated emission point shall not
4 exceed the following concentrations:

5

Emission Points	Concentration (ppm)	lb/hr
Boiler #1	9.0	1.3
Boiler #2	9.0	1.3

6
7
8
9
10 Compliance to the above emission limits shall be determined by stack test as outlined in
11 Section IX Part H.11.e of this SIP. A compliance test shall be performed at least ~~once~~
12 ~~every three years~~ annually subsequent to the initial compliance test.

13
14 ii. PM_{2.5} emissions (filterable+condensable) to the atmosphere from each of the
15 following emission points shall not exceed the listed concentration and lb/hr
16 emission rates:

17
18 Emission Unit PM_{2.5} Emission Rate (lb/hr) Concentration Emission Rate (grains/dscf)

AH-500	1.61	0.01
AH-502	0.7 <u>5</u> 4	0.04
AH-513	1.49	0.0114
BH-001	0.37	0.01
BH-002	0.47	0.01
BH-008	1.15 <u>4.25</u>	0.01
BH-501	1.15	0.01
BH-502	0.06	0.0053
BH-503	0.23	0.01
BH-505	0.12	0.01
AH-1555	0.14 <u>0.39</u>	0.01
BH-1400	2.78	0.02
AH-692	0.12	0.01
BH-1516	0.22	0.01

19
20
21
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24
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27
28
29
30
31
32
33
34
35 A. Compliance to the above emission limits shall be determined by stack test as outlined
36 in Section IX Part H.11.e of this SIP. Compliance testing shall be performed ~~at least~~
37 ~~once every three years~~ annually.

38
39 B. Process emissions shall be routed through operating controls prior to being emitted to
40 the atmosphere.

41
42 iii. Emissions of VOC from all Magnesium Chloride Evaporators (four stacks total) shall
43 not exceed 6.18 lb/hr.

44
45 A. Compliance shall be determined by stack test as outlined in Section IX Part H.11.e of
46 this SIP. Compliance testing shall be performed at least ~~once every three~~

1
2
3
4
5

~~years~~ annually.

- B. Process emissions shall be routed through operating controls prior to being emitted to the atmosphere.

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1 f. Hexcel Corporation: Salt Lake Operations

2
3 i. The following limits shall not be exceeded for fiber line
4 operations:

5
6 A. 5.50 MMscf of natural gas consumed per day.

7
8 B. 0.061 MM pounds of carbon fiber produced per day.

9
10 C. Compliance with each limit shall be determined by the following methods:

11
12 I. Natural gas consumption shall be determined by examination of natural
13 gas billing records for the plant and onsite pipe-line metering.

14
15 II. Fiber production shall be determined by examination of plant production records.

16
17 III. Records of consumption and production shall be kept on a daily basis for all
18 periods when the plant is in operation.

19
20 ii. After a shutdown and prior to startup of fiber lines 13 to 16, the line's
21 baghouse(s) and natural gas injection dual chambered regenerative thermal
22 oxidizer shall be started and remain in operation during production.

23
24 A. During fiber line production, the static pressure differential across the filter media
25 shall be within the manufacturer's recommended range and shall be recorded daily.

26
27 B. The manometer or the differential pressure gauge shall be calibrated according to the
28 manufacturer's instructions at least once every 12 months.

29
30 iii. Filter boxes will be installed on Fiber lines 13 and 14 to control PM_{2.5} emissions no
31 later than December 31, 2019.

32
33 iv. Ultra Low NO_x Burners with flue gas recirculation shall be installed on Fiber lines 3,
34 4, and 7 to control NO_x emissions no later than December 31, 2024.

35
36 A. Emission limitations ~~[will not be listed here, part of the exhaust stream will~~
37 ~~include the NO_x generated from the oxidation of PAN in the carbon fiber~~
38 ~~production process and these emissions are not well defined. Emission limits~~
39 ~~will be present at a later date in the Approval Order as well as the Title V~~
40 ~~Operating Permit when they are better known.]for NO_x shall be as follows:~~

41
42 Concentration (ppm)

43
44 Fiber Line 3 9.0

45
46 Fiber Line 4 9.0

B. Stack testing shall be performed at least once annually baased upon the date of the last compliance test and at a time when PAN is not being introduced into the burners.

v. De-NO_x Water Direct Fired Thermal Oxidizer (DFTO) shall be installed on Fiber lines 13, 14, 15, and 16 to control NO_x emissions no later than December 31, 2024.

vi. After a shutdown and prior to startup of the fiber lines, the residence time and temperature associated with the regenerative thermal-oxidation fume incinerators and solvent-coating fume incinerators shall be started and remain in operation during production.

A. Unless otherwise indicated, the carbon fiber production thermal-oxidation fume incinerators the minimum temperature shall be 1,400 deg F and the residence time shall be greater than or equal to 0.5 seconds

Solvent-coating fume incinerators the minimum temperature shall be 1,450 deg F and the residence time shall be greater than or equal to 0.5 seconds

For fiber lines 6, 7, 8, 10, 11, 12, and the line associated with the Research and Development Facility, the solvent coating fume incinerators temperature shall range from 1,400 to 1,700 deg F and the residence time shall be greater than or equal to 1.0 second

Residence times shall be determined by:

$$R = V / Q_{max}$$

Where

R = residence time

V = interior volume of the incinerator – ft³

Q_{max} = maximum exhaust gas flow rate – ft³/second

B. Incinerator temperatures shall be monitored with temperature sensing equipment that is capable of continuous measurement and readout of the combustion temperature. The readout shall be located such that an inspector/operator can at any time safely read the output. The measurement shall be accurate within ± 25°F at operating temperature. The measurement need not be continuously recorded. All instruments shall be calibrated against a primary standard at least once every 180 days. The calibration procedure shall be in accordance with 40 CFR 60, Appendix A, Method 2, paragraph 6.3, and 10.31, or use a type "K" thermocouple.

1 g. Holly Corporation: Holly Refining & Marketing Company (Holly Refinery)

2
3 i. Source-wide PM_{2.5} Cap

4
5 No later than January 1, 2019, PM_{2.5} emissions (filterable + condensable) from all
6 combustion sources shall not exceed 47.6 tons per rolling 12-month period and 0.134
7 tons per day (tpd).

8
9 A. Setting of emission factors:

10 The emission factors derived from the most current performance test shall be
11 applied to the relevant quantities of fuel combusted. Unless adjusted by
12 performance testing as discussed in IX.H.12.i.i.B below, the default emission
13 factors to be used are as follows:

14
15 Natural gas or Plant gas:

16 non-NSPS combustion equipment: 7.65 lb PM_{2.5}/MMscf

17 NSPS combustion equipment: 0.52 lb PM_{2.5}/MMscf

18
19 Fuel oil:

20 The filterable PM_{2.5} emission factor for fuel oil combustion shall be determined
21 based on the sulfur content of the oil as follows:

22
23
$$\text{PM}_{2.5} \text{ (lb/1000 gal)} = (10 * \text{wt. \% S}) + 3$$

24
25 The condensable PM_{2.5} emission factor for fuel oil combustion shall be determined
26 from the latest edition of AP-42.

27
28 FCC Wet Scrubbers:

29 The PM_{2.5} emission factors shall be based on the most recent stack test and
30 verified by parametric monitoring as outlined in IX.H.11.g.i.B.III. As an
31 alternative to a continuous parameter monitor system or continuous opacity
32 monitoring system for PM emissions from any FCCU controlled by a wet gas
33 scrubber, as required in Subsection IX.H.11.g.i.B.III, the owner/operator may
34 satisfy the opacity monitoring requirements from its FCC Units with wet gas
35 scrubbers through an alternate monitoring program as approved by the EPA and
36 acceptable to the Director.

37
38 B. The default emission factors listed in IX.H.12.i.i.A above apply until such time as
39 stack testing is conducted as outlined below:

40
41 Initial stack testing on all NSPS combustion equipment shall be conducted no
42 later than January 1, 2019 and at least ~~once every three (3) years~~ annually
43 thereafter. At that time a new flow-weighted average emission factor in terms of:
44 lb PM_{2.5}/MMBtu shall be derived. Stack testing shall be performed as outlined in
45 IX.H.11.e.
46

1 C. Compliance with the source-wide PM_{2.5} Cap shall be determined for each day as
2 follows: Total 24-hour PM_{2.5} emissions for the emission points shall be calculated
3 by adding the daily results of the PM_{2.5} emissions equations listed below for natural
4 gas, plant gas, and fuel oil combustion. These emissions shall be added to the
5 emissions from the wet scrubbers to arrive at a combined daily PM_{2.5} emission
6 total.

7
8 For purposes of this subsection a “day” is defined as a period of 24-hours
9 commencing at midnight and ending at the following midnight.

10
11 Daily natural gas and plant gas consumption shall be determined through the use of
12 flow meters on all gas-fueled combustion equipment.

13
14 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
15 tanks that supply fuel oil to combustion sources.

16
17 The equations used to determine emissions for the boilers and furnaces shall
18 be as follows:

19
20 Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural/Plant Gas
21 Consumption
22 (MMscf/day)/(2,000 lb/ton)

23
24 Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption
25 (kgal/day)/(2,000 lb/ton)

26
27 Results shall be tabulated for each day, and records shall be kept which include all
28 meter readings (in the appropriate units), and the calculated emissions.

29
30 ii. Source-wide NO_x Cap

31
32 No later than January 1, 2019, NO_x emissions into the atmosphere from all emission
33 points shall not exceed 347.1 tons per rolling 12-month period and 2.09 tons per day
34 (tpd).

35
36 A. Setting of emission factors:

37 The emission factors derived from the most current performance test shall be
38 applied to the relevant quantities of fuel combusted.

39
40 Unless adjusted by performance testing as discussed in IX.H.12.i.ii.B below, the
41 default emission factors to be used are as follows:

42
43 Natural gas/refinery fuel gas combustion using:

44 Low NO_x burners (LNB): 41 lbs/MMscf

45 Ultra-Low NO_x (ULNB) burners: 0.04 lbs/MMbtu

46 Next Generation Ultra Low NO_x burners (NGULNB): 0.10 lbs/MMbtu

1 Boiler #5: 0.02 lbs/MMbtu
2 All other boilers with selective catalytic reduction (SCR): 0.02 lbs/MMbtu
3 All other combustion burners: 100 lb/MMscf
4

5 Where:

6 "Natural gas/refinery fuel gas" shall represent any combustion of natural gas,
7 refinery fuel gas, or combination of the two in the associated burner.
8

9 All fuel oil combustion: 120 lbs/Kgal
10

11 B. The default emission factors listed in IX.H.12.k.ii.A above apply until such time as
12 stack testing is conducted as outlined in IX.H.11.e or by NSPS.
13

14 C. Compliance with the Source-wide NO_x Cap shall be determined for each day as
15 follows: Total daily NO_x emissions for emission points shall be calculated by
16 adding the results of
17 the NO_x equations for plant gas, fuel oil, and natural gas combustion listed below.
18 For
19 purposes of this subsection a "day" is defined as a period of 24-hours
20 commencing at midnight and ending at the following midnight.
21

22 Daily natural gas and plant gas consumption shall be determined through the use of
23 flow meters.
24

25 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
26 tanks that supply combustion sources.
27

28 The equations used to determine emissions for the boilers and furnaces shall
29 be as follows:
30

31 Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural Gas Consumption
32 (MMscf/day)/(2,000 lb/ton)
33

34 Emissions (tons/day) = Emission Factor (lb/MMscf) * Plant Gas Consumption
35 (MMscf/day)/(2,000 lb/ton)
36

37 Emissions (tons/day) = Emission Factor (lb/MMBTU) * Burner Heat Rating
38 (BTU/hr)*
39 24 hours per day /(2,000 lb/ton)
40

41 Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption
42 (kgal/day)/(2,000 lb/ton)
43

44 Results shall be tabulated for each day; and records shall be kept which include the
45 meter readings (in the appropriate units), emission factors, and the calculated
46 emissions.

1
2 iii. Source-wide SO₂ Cap

3 No later than January 1, 2019, the emission of SO₂ from all emission points
4 (excluding routine SRU turnaround maintenance emissions) shall not exceed 110.3
5 tons per rolling 12- month period and 0.31 tons per day (tpd).
6

7 A. Setting of emission factors:

8 The emission factors listed below shall be applied to the relevant quantities
9 of fuel combusted:

10
11 Natural gas - 0.60 lb SO₂/MMscf
12

13 Plant gas - The emission factor to be used in conjunction with plant gas combustion
14 shall be determined through the use of a CEM which will measure the H₂S content
15 of the fuel gas. The CEM shall operate as outlined in IX.H.11.f.
16

17 Fuel oil - The emission factor to be used in conjunction with fuel oil combustion
18 shall be calculated based on the weight percent of sulfur, as determined by ASTM
19 Method D-4294-89 or EPA-approved equivalent, and the density of the fuel oil, as
20 follows:

21
22 $(\text{lb of SO}_2/\text{kgal}) = (\text{density lb/gal}) * (1000 \text{ gal/kgal}) * (\text{wt. \%S})/100 * (64 \text{ g SO}_2/32$
23 $\text{g S})$
24

25 The weight percent sulfur and the fuel oil density shall be recorded for each day
26 any fuel oil is combusted.
27

28 B. Compliance with the Source-wide SO₂ Cap shall be determined for each day as
29 follows: Total daily SO₂ emissions shall be calculated by adding daily results of the
30 SO₂ emissions
31 equations listed below for natural gas, plant gas, and fuel oil combustion. For
32 purposes
33 of this subsection a “day” is defined as a period of 24-hours commencing at
34 midnight and ending at the following midnight.
35

36 The equations used to determine emissions are:

37
38 $\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Natural Gas Consumption}$
39 $(\text{MMscf/day})/(2,000 \text{ lb/ton})$
40

41 $\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Plant Gas Consumption}$
42 $(\text{MMscf/day})/(2,000 \text{ lb/ton})$
43

44 $\text{Emissions (tons/day)} = \text{Emission Factor (lb/kgal)} * \text{Fuel Oil Consumption}$
45 $(\text{kgal/24 hrs})/(2,000 \text{ lb/ton})$
46

1 For purposes of these equations, fuel consumption shall be measured as outlined
2 below: Daily natural gas and plant gas consumption shall be determined through
3 the use of flow meters.

4
5 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
6 tanks that supply combustion sources.

7
8 Results shall be tabulated for each day, and records shall be kept which include CEM
9 readings for H₂S (averaged for each one-hour period), all meter reading (in the
10 appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel
11 oil is burned), and the calculated emissions.

12
13 iv. Emergency and Standby Equipment

14
15 A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in
16 standby or emergency equipment at all times.

17
18 vi. No later than January 1, 2019, the owner/operator shall install the following to control
19 emissions from the listed equipment:

20

Emission Unit	Control Equipment
Process heaters and boilers	Boilers 8&11: LNB+SCR Boilers 5, 9 & 10: SCR Process heaters 20H2, 20H3 23H1, 24H1, 25H1: ULNB
Cooling water towers 10, 11	High efficiency drift eliminators
FCCU regenerator stacks	WGS with Lo-TOx
Flares	Flare gas recovery system
Sulfur recovery unit	Tail gas incineration and WGS with Lo-TOx
Wastewater treatment plant	API separators, dissolved gas floatation (DGF), moving bed bio-film reactors (MBBR)

21
22

1 h. Kennecott Utah Copper (KUC): Mine

2
3 i. Bingham Canyon Mine (BCM)

- 4
5 A. Maximum total mileage per calendar day for ore and waste haul trucks shall not
6 exceed 30,000 miles.

7
8 KUC shall keep records of daily total mileage for all periods when the mine is in
9 operation. KUC shall track haul truck miles with a Global Positioning System or
10 equivalent. The system shall use real time tracking to determine daily mileage.

- 11
12 B. To minimize fugitive dust on roads at the mine, the owner/operator shall perform the
13 following measures:

14
15 I. Apply water to all active haul roads as weather and operational conditions
16 warrant except during precipitation or freezing weather conditions, and shall
17 apply a chemical dust suppressant to active haul roads located outside of the pit
18 influence boundary no less than twice per year.

19
20 II. Chemical dust suppressant shall be applied as weather and operational
21 conditions warrant except during precipitation or freezing weather conditions on
22 unpaved access roads that receive haul truck traffic and light vehicle traffic.

23
24 III. Records of water and/or chemical dust control treatment shall be kept for all
25 periods when the BCM is in operation.

26
27 IV. KUC is subject to the requirements in the most recent federally approved
28 Fugitive Emissions and Fugitive Dust rules.

- 29
30 C. The In-pit crusher baghouse shall not exceed a $PM_{2.5}$ emission limit of 0.78
31 lbs/hr.(0.007 gr/dscf) $PM_{2.5}$ monitoring shall be performed by stack testing [~~every-~~
32 ~~three years~~ annually.

- 33
34 D. Minimum design payload per ore and waste haul truck shall not be less than 240
35 tons. The minimum design payload for all trucks combined shall be an average of
36 300 tons.

37
38 ii. Copperton Concentrator (CC)

- 39
40 A. Control emissions from the Product Molybdenite Dryers with a scrubber during
41 operation of the dryers.

42
43 During operation of the dryers, the static pressure differential between the inlet and
44 outlet of the scrubber shall be within the manufacturer's recommended range and
45 shall be recorded weekly.

46
47 The manometer or the differential pressure gauge shall be calibrated according to the
48 manufacturer's instructions at least once per year.

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4

The remaining heaters shall not operate more than 300 hours per rolling 12- month period unless upgraded so the NOx emission rate is no greater than 30 ppm.

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1 j. Kennecott Utah Copper (KUC): Power Plant

2
3 i. Utah Power Plant

4
5 A. The following requirements are applicable to Unit #4:

6
7 I. ~~During the period from November 1, to the last day in February inclusive,~~
8 e) Only natural gas shall only be used as a fuel, unless the supplier or transporter
9 of natural gas imposes a curtailment. Unit #4 may then burn coal, only for the
10 duration of the curtailment plus sufficient time to empty the coal bins following
11 the curtailment. The Director shall be notified of the curtailment within 48 hours
12 of when it begins and within 48 hours of when it ends.

13
14 II. Emissions to the atmosphere when burning natural gas shall not exceed the
15 following rates and concentrations:

16

Pollutant	grains/dscf 68°F. 29.92 in Hg	ppmdv 3% O ₂	lbs/hr	lbs/MMBtu	lbs/event
17 1. PM _{2.5} :					
18 Filterable	0.004				
19 Filterable +					
20 condensable	0.03				
21 2. NO _x :		20	17.0	0.02	
22 Startup / Shutdown					395

23
24
25
26

27 III. ~~During the period from March 1 to October 31, Unit #4 shall use coal, natural
28 gas, or oils as fuels.~~

29
30 IV. ~~When burning coal Unit #4 shall not exceed the following emission rates to the atmosphere:~~

31

Pollutant	grains/dscf	ppmdv	lbs/hr	lbs/MMBTU	lbs/event
	68°F.			3% O₂	
	29.92 in Hg				
32 1. PM_{2.5}:					
33 Filterable	0.029				
34 Filterable +					
35 condensable	0.29				
36 2. NO_x:		80		0.06	
37 Startup / Shutdown					395

38
39
40
41

42 ~~* Except during startup and shutdown.~~

43 3. ~~SO₂:~~ ~~290~~ ~~0.34~~

44
45 V. ~~Startup / Shutdown Limitations:~~

- 46
47 1. The total number of startups and shutdowns together shall not exceed 690 per
48 calendar year.
- 49
50 2. The NO_x emissions shall not exceed 395 lbs from each startup/shutdown event,
51 which shall be determined using manufacturer data.
- 52

1 3. Definitions:

- 2
- 3 (i) Startup cycle duration ends when the unit achieves half of the design electrical
- 4 generation capacity.
- 5
- 6 (ii) Shutdown duration cycle begins with the initiation of boiler shutdown and ends
- 7 when fuel flow to the boiler is discontinued.
- 8

9 B. Upon commencement of operation of Unit #4, stack testing to demonstrate compliance

10 with each emission limitation-in IX.H.12. [X].i.A and IX.H.12. [X].i.B shall be

11 performed as follows:

12

13 * Initial compliance testing for the Unit 4 boiler is required. Initial testing shall be

14 performed when burning natural gas [~~and also when burning coal as fuel~~]. The initial

15 test shall be performed within 60 days after achieving the maximum heat input

16 capacity production rate at which the affected facility will be operated and in no case

17 later than 180 days after the initial startup of a new emission source.

18

19 The limited use of natural gas during maintenance firings and break-in firings does not

20 constitute operation and does not require stack testing.

21

22 Pollutant Test Frequency

- 23
- 24 I. PM_{2.5} every year
- 25 II. NO_x every year
- 26 [~~III. [NH₄]SO₂—every year~~]
- 27

28 C. Unit #5 (combined cycle, natural gas-fired combustion turbine) shall not exceed

29 the following emission rates to the atmosphere:

30

31

Pollutant	lbs/hr	lbs/event	ppmdv (15% O ₂ dry)
I. PM _{2.5} with duct firing: Filterable + condensable	18.8		
II. VOC:			2.0*
III. NO _x : Startup / Shutdown	395		2.0*

32

33

34

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40

41 * Except during startup and shutdown.

42

43 IV. Startup / Shutdown Limitations:

44

- 45 1. The total number of startups and shutdowns together shall not exceed 690 per
- 46 calendar year.
- 47
- 48 2. The NO_x emissions shall not exceed 395 lbs from each startup/shutdown event,
- 49 which shall be determined using manufacturer data.
- 50

51 3. Definitions:

52

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- (i) Startup cycle duration ends when the unit achieves half of the design electrical generation capacity.
- (ii) Shutdown duration cycle begins with the initiation of boiler shutdown and ends when fuel flow to the boiler is discontinued.

D: Upon commencement of operation of Unit #5*, stack testing to demonstrate compliance with the emission limitations in IX.H.12.m.i.B shall be performed as follows for the following air contaminants

* Initial compliance testing for the natural gas turbine and duct burner is required. The initial test shall be performed within 60 days after achieving the maximum heat input capacity production rate at which the affected facility will be operated and in no case later than 180 days after the initial startup of a new emission source.

The limited use of natural gas during maintenance firings and break-in firings does not constitute operation and does not require stack testing.

Pollutant	Test Frequency
I. PM _{2.5}	every year
II. NO _x	every year
III. VOC	every year

1 j. Kennecott Utah Copper: Smelter and Refinery

2
3 i. Smelter:

4
5 A. Emissions to the atmosphere from the indicated emission points shall not exceed the
6 following rates and concentrations:

7
8 I. Main Stack (Stack No. 11)

- 9
10 1. PM_{2.5}
11 a. 85 lbs/hr (filterable)
12 b. 434 lbs/hr (filterable + condensable)
13
14 2. SO₂
15 a. 552 lbs/hr (3 hr. rolling average)
16 b. 422 lbs/hr (daily average)
17
18 3. NO_x 154 lbs/hr (daily average)

19
20 II. Holman Boiler

- 21
22 1. NO_x
23 a. 14 lbs/hr, (calendar-day average)

24
25 B. Stack testing to show compliance with the emissions limitations of Condition (A)
26 above shall be performed as specified below:

27
28

EMISSION POINT	POLLUTANT	TEST FREQUENCY
I. Main Stack (Stack No. 11)	PM _{2.5}	Every Year
	SO ₂	CEM
	NO _x	CEM
II. Holman Boiler	NO _x	Every three year[s] and CEMS or alternate method according to applicable NSPS standards

29
30
31
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38

39 The Holman boiler shall use an EPA approved test method ~~every three years and in~~
40 ~~between years use~~ annually or an approved CEMS or alternate method according to
41 applicable NSPS standards.
42

43 C. During startup/shutdown operations, NO_x and SO₂ emissions are monitored by
44 CEMS or alternate methods in accordance with applicable NSPS standards.
45

46 D. KUC must operate and maintain the air pollution control equipment and monitoring
47 equipment in a manner consistent with good air pollution control practices for
48 minimizing emissions at all times including during startup, shutdown, and
49 malfunction.
50

51 ii. Refinery:

1 A. Emissions to the atmosphere from the indicated emission point shall not exceed the
2 following rate:

3	EMISSION POINT	POLLUTANT	MAXIMUM EMISSION RATE
4			
5			
6	The sum of two		
7	(Tankhouse) Boilers	NO _x	9.5 lbs/hr (before December 2020)
8			
9	(Upgraded		
10	Tankhouse Boiler)	NO _x	1.5 lbs/hr (After December 2020)
11			
12	Combined Heat Plant	NO _x	5.96 lbs/hr
13			

14 B. Stack testing to show compliance with the above emission limitations shall be
15 performed as follows:

16	EMISSION POINT	POLLUTANT	TESTING FREQUENCY
17			
18			
19	Upgraded Tankhouse		
20	Boilers	NO _x	every three year[s*]
21			
22	Combined Heat Plant	NO _x	every year
23			

24 [~~*Stack testing shall be performed on boilers that have operated more than 300 hours~~
25 ~~during a three year period.~~]

26
27 C. One 82 MMBTU/hr Tankhouse boiler shall be upgraded to meet a NO_x rating of 9
28 ppm no later than December 31, 2020. The remaining Tankhouse boiler shall not
29 consume more than 100,000 MCF of natural gas per rolling 12- month period unless
30 upgraded so the NO_x emission rate is no greater than 30 ppm

31
32 D. KUC must operate and maintain the stationary combustion turbine, air pollution
33 control equipment, and monitoring equipment in a manner consistent with good air
34 pollution control practices for minimizing emissions at all times including during
35 startup, shutdown, and malfunction. Records shall be kept on site which indicate the
36 date and time of startups and shutdowns.
37

1 k. Nucor Steel Mills

2
3 i. Emissions to the atmosphere from the indicated emission points shall not exceed the
4 following rates:

5
6 A. Electric Arc Furnace Baghouse

7
8 I. PM_{2.5}

- 9 1. 17.4 lbs/hr (24 hr. average filterable)
10 2. 29.53 lbs/hr (24 hr. average condensable)

11
12 II. SO₂

- 13 1. 93.98 lbs/hr (3 hr. rolling average)
14 2. 89.0 lbs/hr (daily average)

15
16 III. NO_x 59.5 lbs/hr (calendar-day average)

17
18 IV. VOC 22.20 lbs/hr

19
20 B. Reheat Furnace #1

21 NO_x 15.0 lb/hr

22
23 C. Reheat Furnace #2

24 NO_x 8.0 lb/hr

25
26 ii. Stack testing to show compliance with the emissions limitations of Condition (i)
27 above shall be performed as outlined in IX.H.11.e and as specified below:

28
29

EMISSION POINT	POLLUTANT	TEST FREQUENCY
A. Electric Arc Furnace Baghouse	PM _{2.5}	every year
	SO ₂	CEM
	NO _x	CEM
	VOC	every year
B. Reheat Furnace #1	NO _x	every year
C. Reheat Furnace #2	NO _x	every year

30
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40 iii. Testing Status (To be applied to (i) and (ii) above)

41
42 A. To demonstrate compliance with the Electric Arc Furnace stack mass emissions
43 limits for SO₂ and NO_x of Condition (i)(A) above, Nucor shall calibrate, maintain
44 and operate the measurement systems for continuously monitoring for SO₂ and NO_x
45 concentrations and stack gas volumetric flow rates in the Electric Arc Furnace stack.
46 Such measurement systems shall meet the requirements of R307-170.

47
48 B. For PM_{2.5} testing, 40 CFR 60, Appendix A, Method 5D, or another EPA approved
49 method acceptable to the Director, shall be used to determine total TSP emissions. If
50 TSP emissions are below the PM_{2.5} limit, that will constitute compliance with the
51 PM_{2.5} limit. If TSP emissions are not below the PM_{2.5} limit, the owner/operator shall
52 retest using EPA approved methods specified for PM_{2.5} testing, within 120 days.
53

C. Startup/shutdown NO_x and SO₂ emissions are monitored by CEMS.

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1 I. PacifiCorp Energy: Gadsby Power Plant

2
3 i. Steam Generating Unit #1:

4
5 A. Emissions of NO_x shall be no greater than 179 lbs/hr on a three (3) hour block
6 average basis.

7
8 B. Emissions of NO_x shall not exceed 336 ppm_{dv} (@ 3% O₂, dry)

9
10 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
11 CEM consisting of NO_x and O₂ monitors to determine compliance with the
12 NO_x limitation. The CEM shall operate as outlined in IX.H.11.f.

13
14 ii. Steam Generating Unit #2:

15
16 A. Emissions of NO_x shall be no greater than 204 lbs/hr on a three (3) hour block
17 average basis.

18
19 B. Emissions of NO_x shall not exceed 336 ppm_{dv} (@ 3% O₂, dry)

20
21 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
22 continuous emission monitoring system (CEMS) consisting of NO_x and O₂
23 monitors to determine compliance with the NO_x limitation.

24
25 iii. Steam Generating Unit #3:

26 A. Emissions of NO_x shall be no greater than

27
28 I. 142 lbs/hr on a three (3) hour block average basis [~~-, applicable between~~
29 ~~November 1 and February 28/29.~~

30
31 ~~II. 203 lbs/hr on a three (3) hour block average basis, applicable between March~~
32 ~~1 and October 31].~~

33
34 B. Emissions of NO_x shall not exceed

35
36 I. 168 ppm_{dv} (@ 3% O₂, dry) [~~-, applicable between November 1 and February~~
37 ~~28/29~~

38
39 ~~II. 168 ppm_{dv} (@ 3% O₂, dry), applicable between applicable between March 1~~
40 ~~and October 31].~~

41
42 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
43 CEM consisting of NO_x and O₂ monitors to determine compliance with the
44 NO_x limitation. The CEM shall operate as outlined in IX.H.11.f.

45
46 iv. Steam Generating Units #1-3:

1 A. The owner/operator shall use only natural gas as a primary fuel and No. 2 fuel oil or
2 better as back-up fuel in the boilers. The No. 2 fuel oil may be used only during
3 periods of natural gas curtailment and for maintenance firings. Maintenance firings
4 shall not exceed one-percent of the annual plant Btu requirement. In addition,
5 maintenance firings shall be scheduled between April 1 and November 30 of any
6 calendar year. Records of fuel oil use shall be kept and they shall show the date the
7 fuel oil was fired, the duration in hours the fuel oil was fired, the amount of fuel oil
8 consumed during each curtailment, and the reason for each firing.
9

10 v. Natural Gas-fired Simple Cycle, Catalytic-controlled Turbine Units:
11

12 A. Total emissions of NO_x from all three turbines shall be no greater than 600
13 lbs/day. For purposes of this subsection a “day” is defined as a period of 24-hours
14 commencing at midnight and ending at the following midnight.
15

16 B. Emissions of NO_x from each turbine stack shall not exceed 5 ppmvd (@ 15% O₂
17 dry). Emissions shall be calculated on a 30-day rolling average. This limitation
18 applies to steady state operation, not including startup and shutdown.
19

20 C. The owner/operator shall install, certify, maintain, operate, and quality-assure a
21 CEM consisting of NO_x and O₂ monitors to determine compliance with the
22 NO_x limitation. The CEM shall operate as outlined in IX.H.11.f.

1 vi. Combustion Turbine Startup / Shutdown Emission Minimization Plan

- 2
- 3 A. Startup begins when the fuel valves open and natural gas is supplied to the combustion
- 4 turbines
- 5
- 6 B. Startup ends when either of the following conditions is met:
- 7
- 8 I. The NO_x water injection pump is operational, the dilution air temperature is greater
- 9 than 600°F, the stack inlet temperature reaches 570°F, the ammonia block valve has
- 10 opened and ammonia is being injected into the SCR and the unit has reached an
- 11 output of ten (10) gross MW; or
- 12
- 13 II. The unit has been in startup for two (2) hours.
- 14
- 15 C. Unit shutdown begins when the unit load or output is reduced below ten (10) gross MW
- 16 with the intent of removing the unit from service.
- 17
- 18 D. Shutdown ends at the cessation of fuel input to the turbine combustor.
- 19
- 20 E. Periods of startup or shutdown shall not exceed two (2) hours per combustion turbine
- 21 per day.
- 22
- 23 F. Turbine output (turbine load) shall be monitored and recorded on an hourly basis with
- 24 an electrical meter.

1 m. Tesoro Refining and Marketing Company: Salt Lake City Refinery

2
3 i. Source-wide PM_{2.5} Cap

4
5 No later than January 1, 2019, combined emissions of PM_{2.5} (filterable+condensable)
6 shall not exceed 2.25 tons per day (tpd) and 179 tons per rolling 12-month period.
7

8 A. Setting of emission factors:

9
10 The emission factors derived from the most current performance test shall be
11 applied to the relevant quantities of fuel combusted. Unless adjusted by
12 performance testing as discussed in IX.H.12.p.i.B below, the default emission
13 factors to be used are as follows:
14

15 Natural gas:

16 Filterable PM_{2.5}: 0.0019 lb/MMBtu

17 Condensable PM_{2.5}: 0.0056 lb/MMBtu
18

19 Plant gas:

20 Filterable PM_{2.5}: 0.0019 lb/MMBtu

21 Condensable PM_{2.5}: 0.0056 lb/MMBtu
22

23 Fuel Oil: The PM_{2.5} emission factor shall be determined from the latest edition of
24 AP-42
25

26 FCC Wet Scrubber:

27 The PM_{2.5} emission factors shall be based on the most recent stack test and verified
28 by parametric monitoring as outlined in IX.H.11.g.i.B.III
29

30 Where mixtures of fuel are used in a Unit, the above factors shall be weighted
31 according to the use of each fuel.
32

33 B. The default emission factors listed in IX.H.12.m.i.A above apply until such time as
34 stack testing is conducted as outlined below:
35

36 Initial PM_{2.5} stack testing on the FCC wet gas scrubber stack shall be conducted no
37 later than January 1, 2019 and at least ~~[once every three (3) years]~~ annually
38 thereafter. Stack testing shall be performed as outlined in IX.H.11.e.
39

40 C. Compliance with the Source-wide PM_{2.5} Cap shall be determined for each day as
41 follows: Total 24-hour PM_{2.5} emissions for the emission points shall be calculated
42 by adding the daily results of the PM_{2.5} emissions equations listed below for natural
43 gas, plant gas, and fuel oil combustion. These emissions shall be added to the
44 emissions from the wet scrubber to arrive at a combined daily PM_{2.5} emission total.
45 For purposes of this subsection a “day” is defined as a period of 24-hours
46 commencing at midnight and ending at the following midnight.

1
2 Daily natural gas and plant gas consumption shall be determined through the use of
3 flow meters.

4
5 Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks
6 that supply combustion sources.

7
8 The emissions for each emitting unit shall be calculated by multiplying the hours of
9 operation of a unit feed rate to a unit, or quantity of each fuel combusted at each
10 affected unity by the associated emission factor, and summing the results.

11
12 Results shall be tabulated for each day, and records shall be kept which include the
13 meter readings (in the appropriate units) and the calculated emissions.

14
15 ii. Source-wide NO_x Cap

16
17 No later than January 1, 2019, combined emissions of NO_x shall not exceed 2.3 tons
18 per day (tpd) and 475 tons per rolling 12-month period.

19
20 A. Setting of emission factors:

21
22 The emission factors derived from the most current performance test shall be
23 applied to the relevant quantities of fuel combusted. Unless adjusted by
24 performance testing as discussed in IX.H.12.m.ii.B below, the default emission
25 factors to be used are as follows:

26
27 Natural gas/refinery fuel gas combustion using:

28 Low NO_x burners (LNB):0.051 lbs/MMbtu

29 Ultra-Low NO_x (ULNB) burners: 0.04 lbs/MMbtu

30 Diesel fuel: shall be determined from the latest edition of AP-42

31
32 B. The default emission factors listed in IX.H.12.m.ii.A above apply unless stack
33 testing results are available or emissions are measured by operation of a NO_x
34 CEMS.

35
36 Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment
37 above 100 MMBtu/hr has already been performed and shall be conducted at least
38 annually. At that time a new flow-weighted average emission factor in terms of:
39 lbs/MMbtu shall be derived. Stack testing shall be performed as outlined in
40 IX.H.11.e. Stack testing is not required for natural gas/refinery fuel gas combustion
41 equipment with a NO_x CEMS.

42
43 C. Compliance with the source-wide NO_x Cap shall be determined for each day as
44 follows: Total 24-hour NO_x emissions shall be calculated by adding the emissions
45 for each emitting unit. The emissions for each emitting unit shall be calculated by
46 multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each

1 fuel combusted at each affected unit by the associated emission factor, and
2 summing the results.

3
4 A NO_x CEM shall be used to calculate daily NO_x emissions from the FCCU wet
5 gas scrubber stack. Emissions shall be determined by multiplying the nitrogen
6 dioxide concentration in the flue gas by the flow rate of the flue gas. The NO_x
7 concentration in the flue gas shall be determined by a CEM as outlined in
8 IX.H.11.f.

9
10 Daily natural gas and plant gas consumption shall be determined through the use of
11 flow meters.

12
13 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
14 tanks that supply combustion sources.

15
16 For purposes of this subsection a “day” is defined as a period of 24-hours
17 commencing at midnight and ending at the following midnight.

18
19 Results shall be tabulated for each day, and records shall be kept which include the
20 meter readings (in the appropriate units) and the calculated emissions.

21
22 iii. Source-wide SO₂ Cap

23
24 No later than January 1, 2019, combined emissions of SO₂ shall not exceed 3.8 tons per
25 day (tpd) and 300 tons per rolling 12-month period.

26
27 A. Setting of emission factors:

28
29 The emission factors derived from the most current performance test shall be
30 applied to the relevant quantities of fuel combusted. The default emission factors to
31 be used are as follows:

32
33 Natural gas: EF = 0.0006 lb/MMBtu

34 Propane: EF = 0.0006 lb/MMBtu

35 Diesel fuel: shall be determined from the latest edition of AP-42

36
37 Plant fuel gas: the emission factor shall be calculated from the H₂S measurement or
38 from the SO₂ measurement obtained by direct testing/monitoring.

39
40 Where mixtures of fuel are used in a unit, the above factors shall be weighted
41 according to the use of each fuel.

42
43 B. Compliance with the source-wide SO₂ Cap shall be determined for each day as
44 follows: Total daily SO₂ emissions shall be calculated by adding the daily SO₂
45 emissions for natural gas, plant fuel gas, and propane combustion to those from the
46 wet gas scrubber stack.

1
2 Daily SO₂ emissions from the FCCU wet gas scrubber stack shall be determined by
3 multiplying the SO₂ concentration in the flue gas by the flow rate of the flue gas.
4 The SO₂ concentration in the flue gas shall be determined by a CEM as outlined in
5 IX.H.11.f.

6
7 SRUs: The emission rate shall be determined by multiplying the sulfur dioxide
8 concentration in the flue gas by the flow rate of the flue gas. The sulfur dioxide
9 concentration in the flue gas shall be determined by CEM as outlined in IX.H.11.f

10
11 Daily SO₂ emissions from other affected units shall be determined by multiplying
12 the quantity of each fuel used daily at each affected unit by the appropriate
13 emission factor.

14
15 Daily natural gas and plant gas consumption shall be determined through the use of
16 flow meters.

17
18 Daily fuel oil consumption shall be monitored by means of leveling gauges on all
19 tanks that supply combustion sources.

20
21 Results shall be tabulated for each day, and records shall be kept which include
22 CEM readings for H₂S (averaged for each one-hour period), all meter reading (in
23 the appropriate units), fuel oil parameters (density and wt% sulfur for each day any
24 fuel oil is burned), and the calculated emissions.

- 25
26 C. Instead of complying with Condition IX.H.11.g.ii.A, source may reduce the H₂S
27 content of the refinery plant gas to 60 ppm or less or reduce SO₂ concentration from
28 fuel gas combustion devices to 8 ppmvd at 0% O₂ or less as described in 40 CFR
29 60.102a. Compliance shall be based on a rolling average of 365 days. The
30 owner/operator shall comply with the fuel gas or SO₂ emissions monitoring
31 requirements of 40 CFR 60.107a and the related recordkeeping and reporting
32 requirements of 40 CFR 60.108a. As used herein, refinery “plant gas” shall have
33 the meaning of “fuel gas” as defined in 40 CFR 60.101a, and may be used
34 interchangeably.

35
36 iv. SO₂ emissions from the SRU/TGTU/TGI shall be limited to:

- 37
38 A. 1.68 tons per day (tpd) for up to 21 days per rolling 12-month period, and
39
40 B. 0.69 tpd for the remainder of the rolling 12-month period.
41
42 C. Daily sulfur dioxide emissions from the SRU/TGI/TGTU shall be determined by
43 multiplying the SO₂ concentration in the flue gas by the mass flow of the flue gas.
44 The sulfur dioxide concentration in the flue gas shall be determined by CEM as
45 outlined in IX.H.11.f

46
47 v. Emergency and Standby Equipment

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2
3
4

A. The use of diesel fuel meeting the specifications of 40 CFR 80.510 is allowed in standby or emergency equipment at all times.

5
6

vi. No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:

Emission Unit	Control Equipment
FCCU / CO Boiler	Wet Gas Scrubber, LoTOx
Furnace F-1	Ultra Low NOx Burners
Tanks	Tank Degassing Controls
North and South Flares	Flare Gas Recovery
Furnace H-101	Ultra Low NOx Burners
Truck loading rack	Vapor recovery unit
Sulfur recovery unit	Tail Gas Treatment Unit
API separator	Floating roof (single seal)

7
8

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1 n. The Procter & Gamble Paper Products Company

- 2
3 i. Emissions to the atmosphere at all times from the indicated emission points shall not
4 exceed the following rates:

5
6 Source: Paper Making Boilers (Each)

7

8 Pollutant	Oxygen Ref.	lb/hr
9 NO _x	3%	3.3
10 PM _{2.5} (Filterable and Condensables)	3%	0.9

11
12 Source: Paper Machine Process Stack

13

14 Pollutant	Oxygen Ref.	lb/hr
15 NO _x	3%	13.50
16 PM _{2.5} (Filterable and Condensables)	3%	17.95

17
18 Source: Utility Boilers (Each)

19

20 Pollutant	Oxygen Ref.	lb/hr
21 NO _x	3%	1.8
22 PM _{2.5} (Filterable and Condensables)	3%	0.74

- 23
24 A. Compliance with the above emission limits shall be determined by stack test as
25 outlined in Section IX Part H.11.e of this SIP.

- 26
27 B. Subsequent to initial compliance testing, stack testing is required ~~[at a minimum of~~
28 ~~every three years]~~annually.

29
30 ii. Boiler Startup/Shutdown Emissions Minimization Plan

- 31
32 A. Startup begins when natural gas is supplied to the Boiler(s) with the intent of
33 combusting the fuel to generate steam. Startup conditions end within thirty (30) minutes
34 of natural gas being supplied to the boilers(s).

- 35
36 B. Shutdown begins with the initiation of the stop sequence of the boiler until the
37 cessation of natural gas flow to the boiler.

38
39 iii. Paper Machine Startup/Shutdown Emissions Minimization Plan

- 40
41 A. Startup begins when natural gas is supplied to the dryer combustion equipment with
42 the intent of combusting the fuel to heat the air to a desired temperature for the paper
43 machine. Startup conditions end within thirty (30) minutes of natural gas being
44 supplied to the dryer combustion equipment.

- 45
46 B. Shutdown begins with the diversion of the hot air to the dryer startup stack and then
47 the cessation of natural gas flow to the dryer combustion equipment. Shutdown
48 conditions end within thirty (30) minutes of hot air being diverted to the dryer
49 startup stack.

1 o. University of Utah: University of Utah Facilities

2
3 i Emissions to the atmosphere from the listed emission points in Building 303 LCHWTP
4 shall not exceed the following concentrations:

5 Emissions Point	6 Pollutant	7 ppm _{dv} (3% O ₂ dry)
8 * 9 [Boiler #4*	NO _x	187
10 ⊖ 11 i Boilers #6 & 7	NO _x	9
12 † 13 e Boiler #9*	NO _x	9
14 ‡ 15 # Turbine	NO _x	9
16 4 17 Turbine and WHRU Duct burner	NO _x	15

18 B
19 December 31, 2019, Boiler #4 will be decommissioned and Boiler #9 will be installed and
20 operational.

21
22
23 ii. Stack testing to show compliance with the emissions limitations of Condition i above shall
24 be performed as outlined in IX.H.11.e and as specified below:

25 Emissions Point	26 Pollutant	Initial Test	Test Frequency
Boilers #4*	NO _x	*	[#]every year
Boilers #6 & 7	NO _x	*	[#]every year
Boiler #9*	NO _x	2020	[#]every year
Turbine	NO _x	*	[#]every year
Turbine and WHRU Duct Burner	NO _x	*	[#]every year

27
28 Initial test already performed

29
30 * Initial tests have been performed and the next method test using EPA approved test
31 methods shall be performed within [3]one year[s] of the last stack test. Initial
32 compliance testing for Boiler #9 is required. The initial test date shall be performed
33 within 60 days after achieving the maximum heat input capacity production rate at
34 which the affected facility will be operated and in no case later than 180 days after

1 the initial startup of a new emission source.

2
3 # A compliance test shall be performed at least ~~[once every three years from the date of the~~
4 ~~last compliance test that demonstrated compliance with the emission limit(s)]~~annually.

5 Compliance testing shall be performed using EPA approved test methods acceptable to the
6 Director. The Director shall be notified, in accordance with all applicable rules, of any
7 compliance test that is to be performed.

8
9 iii. Boiler #4 in the LCHWTP shall be decommissioned and replaced by Boiler #9 by
10 December 31, 2019.

11
12 iv. ~~[After the second]~~By the end of the third quarter of calendar year 2019, Boilers #1, #3, and
13 #4 in the UCHWTP shall be limited to a natural gas usage of 530 MMscf per calendar year.

14
15 v. The HSC Transformation Project boilers shall be installed and operational by the end of
16 the ~~[second]~~third quarter of calendar year 2019. The new HSC Transformation Project
17 boilers shall be equipped with low NOx burners rated at 30 ppmvd at 3% O2 or less.

18
19 v Records shall be kept on site which indicate the date, and time of startup and shutdown.
20

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1 p. Utah Municipal Power Association: West Valley Power Plant.
2

- 3 i. Total emissions of NO_x from all five (5) catalytic-controlled turbines combined shall be
4 no greater than 1050 lb of NO_x on a daily basis. For purposes of this subpart, a "day" is
5 defined as a period of 24-hours commencing at midnight and ending at the following
6 midnight.
7
- 8 ii. Emissions of NO_x shall not exceed 5 ppmdv (@ 15% O₂, dry) on a 30-day rolling average.
9
- 10 iii. Total emissions of NO_x from all five (5) catalytic-controlled turbines shall include the
11 sum of all periods in the day including periods of startup, shutdown, and maintenance.
12
- 13 iv. The NO_x emission rate (lb/hr) shall be determined by CEM. The CEM shall
14 operate as outlined in IX.H.11.f.
15

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q. Hill Air Force Base

i. Painting and Depainting Operations

A. VOC emissions from painting and depainting operations shall not exceed 0.58 tons per day (tpd).

I. No later than the 28th of each month, a rolling 30-day VOC emission average shall be calculated for the previous month.

ii. Boilers

A. The combined NO_x emissions for all boilers (except those less than 5 MMBtu/hr) shall not exceed 95 lb/hr. This limit shall not apply during periods of curtailment.

I. No later than the 28th of each month, the NO_x lb/hr emission total shall be calculated for the previous month.

B. No later than December 31, 2024, no boiler shall be operating on base with the capacity over 30 MMBtu/hr and with a manufacture date older than January 1, 1989.

