Utah State Implementation Plan

Emission Limits and Operating Practices

Section IX, Part H

Adopted by the Air Quality Board
, 2019

H.1 General Requirements: Control Measures for Area and Point Sources, Emission Limits and Operating Practices, PM_{10} Requirements

a. Except as otherwise outlined in individual conditions of this Subsection IX.H.1 listed below, the terms and conditions of this Subsection IX.H.1 shall apply to all sources subsequently addressed in Subsection IX.H.2 and IX.H.3. Should any inconsistencies exist between these two subsections, the source specific conditions listed in IX.H.2 and IX.H.3 shall take precedence.

b. Definitions.

   i. The definitions contained in R307-101-2, Definitions, apply to Section IX, Part H.

   ii. Natural gas curtailment means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment.

c. Recordkeeping and Reporting

   i. Any information used to determine compliance shall be recorded for all periods when the source is in operation, and such records shall be kept for a minimum of five years. Any or all of these records shall be made available to the Director upon request, and shall include a period of two years ending with the date of the request.

   ii. Each source shall comply with all applicable sections of R307-150 Emission Inventories.

   iii. Each source shall submit a report of any deviation from the applicable requirements of this Subsection IX.H, including those attributable to upset conditions, the probable cause of such deviations, and any corrective actions or preventive measures taken. The report shall be submitted to the Director no later than 24-months following the deviation or earlier if specified by an underlying applicable requirement. Deviations due to breakdowns shall be reported according to the breakdown provisions of R307-107.

d. Emission Limitations.

   i. All emission limitations listed in Subsections IX.H.2 and IX.H.3 apply at all times, unless otherwise specified in the source specific conditions listed in IX.H.2 and IX.H.3.

   ii. All emission limitations of PM_{10} listed in Subsections IX.H.2 and IX.H.3 include both filterable and condensable PM, unless otherwise specified in the source specific conditions listed in IX.H.2 and IX.H.3.

e. Stack Testing.

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 "SO_2 Removal & PM, SO_2 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_{10}: 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 PM_{10} 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. SO_2: 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.

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 of40 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 SO_2 Emissions

I. Each owner or operator of an FCCU shall comply with an SO_2 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 PM_{10} nonattainment or maintenance area shall reduce the H_2S content of the refinery plant gas to 60 ppm or less as described in 40 CFR 60.102a. Compliance shall be based on a rolling average of 365 days. The owner/operator shall comply with the fuel gas monitoring requirements of 40 CFR 60.107a and the related recordkeeping and reporting requirements of 40 CR 60.108a. As used herein, refinery "plant gas" shall have the meaning of "fuel gas" as defined in 40 CFR 60.101a, and may be used interchangeably.

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

iii. Sulfur Removal Units

A. All petroleum refineries in or affecting any $PM_{2.5}$ nonattainment area or any PM_{10} nonattainment or maintenance area shall require:

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

II. SRUs that meet the SO_2 emission limitations listed in 40 CFR 60.102a(f)(1) or 60.102a(f)(2) as appropriate.

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

C. Compliance shall be demonstrated by daily monitoring of flows to the SRU(s). Continuous monitoring of SO_2 concentration in the exhaust stream shall be conducted via CEM as outlined in IX.H.1.f above. Compliance shall be determined on a rolling 30-day average.

iv. No Burning of Liquid Fuel Oil in Stationary Sources

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

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

v. Requirements on Hydrocarbon Flares.

A. All hydrocarbon flares at petroleum refineries located in or affecting any $PM_{2.5}$ nonattainment area or any PM_{10} nonattainment or maintenance area within the State shall be subject to the flaring requirements of NSPS Subpart Ja (40 CFR 60.100a–109a), if not already subject under the flare applicability provisions of Ja.

B. No later than January 1, 2019, all major source petroleum refineries in or affecting any $PM_{2.5}$ nonattainment area or an PM_{10} nonattainment or maintenance area shall either 1) install and operate a flare gas recovery system designed to limit hydrocarbon flaring produced from each affected flare during normal operations to levels below the values listed in 40 CFR 60.103a(c), or 2) limit flaring during normal operations to 500,000 scfd for each affected flare. Flare gas recovery is not required for dedicated SRU flare and header systems, or HF flare and header systems.

H.2 Source Specific Emission Limitations in Salt Lake County PM_{10} Nonattainment/Maintenance Area

a. Big West Oil Company

i. Source-wide PM_{10} Cap

No later than January 1, 2019, combined emissions of PM_{10} shall not exceed 1.037 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.a.i.B below, the default emission factors to be used are as follows:

Natural gas:
Filterable PM_{10}: 1.9 lb/MMscf
Condensable PM_{10}: 5.7 lb/MMscf

Plant gas:
Filterable PM_{10}: 1.9 lb/MMscf
Condensable PM_{10}: 5.7 lb/MMscf

Fuel Oil: The PM_{10} emission factor shall be determined from the latest edition of AP-42

Cooling Towers: The PM_{10} emission factor shall be determined from the latest edition of AP-42

FCC Stacks: The PM_{10} emission factor shall be established by stack test.

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

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

PM_{10} stack testing on the FCC shall be performed initially 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.

C. Compliance with the source-wide PM_{10} Cap shall be determined for each day as follows:

Total 24-hour PM_{10} emissions for the emission points shall be calculated by adding the daily results of the PM_{10} emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers, and the FCCs to arrive at a combined daily PM_{10} 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 gas consumption shall be measured by meters that can delineate the flow of gas to the boilers, furnaces and the SRU incinerator.

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

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

The daily PM_{10} emissions from the FCC shall be calculated using the following equation:

E = FR * EF

Where:
E = Emitted PM_{10}
FR = Feed Rate to Unit (kbbls/day)
EF = emission factor (lbs/kbbl), established by the most recent stack test

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

ii. Source-Wide NO_x Cap

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

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.a.ii.B below, the default emission factors to be used are as follows:

Natural gas: shall be determined from the latest edition of AP-42
Plant gas: assumed equal to natural gas
Diesel fuel: shall be determined from the latest edition of AP-42

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

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

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

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

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

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

NO_x = Emission Factor (lb/MMscf)*Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton) Where the emission factor is derived from the fuel used, as listed in IX.H.2.a.ii.A above

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

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

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

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

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

iii. Source-Wide SO_2 Cap

No later than January 1, 2019, combined emissions of SO_2 shall not exceed 0.60 tons per day (tpd) and 140 tons per rolling 12-month period.

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. The default emission factors to be used are as follows:

Natural Gas - 0.60 lb SO_2/MMscf gas

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

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

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

EF (lb SO_2/k gal) = density (lb/gal) * (1000 gal/k gal) * wt. % S/100 * (64 lb SO_2/32 lb S)

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

B. Compliance with the source-wide SO_2 Cap shall be determined for each day as follows: Total daily SO_2 emissions shall be calculated by adding the daily SO_2 emissions for natural gas and plant fuel gas combustion, to those from the FCC and SRU stacks.

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

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.

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

Results shall be tabulated for each day, and records shall be kept which include CEM readings for H_2S (averaged for each day), 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. Alternate Startup and Shutdown Requirements

A. During any day which includes startup or shutdown of the FCCU, combined emissions of SO_2 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.

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.

c. Central Valley Water Reclamation Facility: Wastewater Treatment Plant

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

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

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

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

B. The NO_X emission factor for each engine shall be derived from the most recent stack test.

C. NO_X emissions shall be calculated on a daily basis.

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

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

d. Chevron Products Company

i. Source-wide PM_{10} Cap
No later than January 1, 2019, combined emissions of PM_{10} shall not exceed 0.715 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.d.i.B below, the default emission factors to be used are as follows:

Natural gas:
Filterable PM_{10}: 1.9 lb/MMscf
Condensable PM_{10}: 5.7 lb/MMscf

Plant gas:
Filterable PM_{10}: 1.9 lb/MMscf
Condensable PM_{10}: 5.7 lb/MMscf

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

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

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

FCC Stack:
The PM_{10} emission factors shall be based on the most recent stack test and verified by parametric monitoring as outlined in IX.H.1.g.i.B.III

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

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

Initial PM_{10} stack testing on the FCC stack has been performed and shall be conducted at least [~~once every three (3) years from the date of the last stack test~~]annually. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide PM_{10} Cap shall be determined for each day as follows:

Total 24-hour PM_{10} emissions for the emission points shall be calculated by adding the daily results of the PM_{10} emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers, and the FCC to arrive at a combined daily PM_{10} 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.

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

The equation used to determine emissions for the boilers and furnaces shall be as follows:
Emission Factor (lb/MMscf) * Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton) Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

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

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.d.ii.B below, the default emission factors to be used are as follows:

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

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

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

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

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

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

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

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

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.

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 the meter readings (in the appropriate units) and the calculated emissions.

iii. Source-wide SO_2 Cap

No later than January 1, 2019, combined emissions of SO_2 shall not exceed 1.05 tons per day (tpd) and 383.3 tons per rolling 12-month period.

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. The default emission factors to be used are as follows:

FCC: The emission rate shall be determined by the FCC SO_2 CEM as outlined in IX.H.1.f.

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

Natural gas: EF = 0.60 lb/MMscf

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

EF (lb SO_2/k gal) = density (lb/gal) * (1000 gal/k gal) * wt.% S/100 * (64 lb SO_2/32 lb S)

Plant gas: the emission factor shall be calculated from the H_2S measurement obtained from the H_2S CEM.

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

B. Compliance with the source-wide SO_2 Cap shall be determined for each day as follows:

Total daily SO_2 emissions shall be calculated by adding the daily SO_2 emissions for natural gas and plant fuel gas combustion, to those from the FCC and SRU stacks.

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 H_2S (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 and Alternative Fuels

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

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

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

v. Compressor Engine Requirements

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

Engine Number	NO_x in ppmvd @ 0% O_2

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)

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.

f. Holly Refining and Marketing Company

i. Source-wide PM_{10} Cap

No later than January 1, 2019, PM_{10} emissions from all sources shall not exceed 0.416 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.i.B below, the default emission factors to be used are as follows:

Natural gas or Plant gas:
non-NSPS combustion equipment: 7.65 lb PM_{10}/MMscf
NSPS combustion equipment: 0.52 lb PM_{10}/MMscf

Fuel oil:
The filterable PM_{10} emission factor for fuel oil combustion shall be determined based on the sulfur content of the oil as follows:

PM_{10} (lb/1000 gal) = (10 * wt. % S) + 3.22

The condensable PM_{10} emission factor for fuel oil combustion shall be determined from the latest edition of AP-42.

Cooling Towers: The PM_{10} emission factor shall be determined from the latest edition of AP-42.

FCC Wet Scrubbers:
The PM_{10} emission factors shall be based on the most recent stack test and verified by parametric monitoring as outlined in IX.H.1.g.i.B.III. As an alternative to a continuous parameter monitor system or continuous opacity monitoring system for PM emissions from any FCCU controlled by a wet gas scrubber, as required in Subsection IX.H.1.g.i.B.III, the owner/operator may satisfy the opacity monitoring requirements from its FCC Units with wet gas scrubbers through an alternate monitoring program as approved by the EPA and acceptable to the Director.

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

Initial stack testing on all NSPS combustion equipment shall be conducted no later than January 1, 2019 and at least [~~once every three (3) years thereafter~~]annually. At that time a new flow-weighted average emission factor in terms of: lb PM_{10}/MMBtu shall be derived. Stack testing shall be performed as outlined in

IX.H.1.e.

C. Compliance with the source-wide PM_{10} Cap shall be determined for each day as follows:

Total 24-hour PM_{10} emissions for the emission points shall be calculated by adding the daily results of the PM_{10} emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers and wet scrubbers to arrive at a combined daily PM_{10} 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:

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

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

All fuel oil combustion: 120 lbs/Kgal

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

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

Total daily NO_x emissions for emission points shall be calculated by adding the results of the NO_x equations for plant gas, fuel oil, and natural gas combustion listed below. 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.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply 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 Gas Consumption (MMscf/day)/(2,000 lb/ton)

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

Emissions (tons/day) = Emission Factor (lb/MMBTU) * Burner Heat Rating (BTU/hr) * 24 hours per 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 the meter readings (in the appropriate units), emission factors, and the calculated emissions.

iii. Source-wide SO_2 Cap

No later than January 1, 2019, the emission of SO_2 from all emission points (excluding routine SRU turnaround maintenance emissions) shall not exceed 110.3 tons per rolling 12-month period and 0.31 tons per day (tpd).

A. Setting of emission factors:

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

Natural gas - 0.60 lb SO_2/MMscf

Plant gas - The emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a CEM which will measure the H_2S content of the fuel gas. The CEM shall operate as outlined in IX.H.1.f.

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

(lb of SO_2/kgal) = (density lb/gal) * (1000 gal/kgal) * (wt. %S)/100 * (64 g SO_2/32 g S)

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

B. Compliance with the Source-wide SO_2 Cap shall be determined for each day as follows:

Total daily SO_2 emissions shall be calculated by adding daily results of the SO_2 emissions equations listed below for natural gas, plant gas, and fuel oil combustion. For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

The equations used to determine emissions are:

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

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

Emissions (tons/day) = Emission Factor (lb/kgal) * 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 H_2S (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)

g. Kennecott Utah Copper (KUC): Mine

i. Bingham Canyon Mine (BCM)

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

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

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

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

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

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

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

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

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

D. Implementation Schedule

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

ii. Copperton Concentrator (CC)

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

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

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

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

i. Utah Power Plant

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

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

Pollutant	lb/hr	lb/event	ppmdv (15% O_2 dry)
I. PM_{10} with duct firing:			
Filterable + condensable	18.8		
II. NO_X:			2.0
Startup/shutdown		395	

III. Startup / Shutdown Limitations:

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

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

3. Definitions:

(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 turbine shutdown sequence and ends when fuel flow to the gas turbine is discontinued.

C. Upon commencement of operation of Unit #5*, stack testing to demonstrate compliance with the emission limitations in IX.H.2.h.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 date 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_{10}	every year
II. NO_X	every year

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

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

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

Pollutant	grains/dscf	ppmdv (3% O_2)
68^{O}F, 29.92 in. Hg		
1. PM_{10} Units #1, #2, #3 and #4		
filterable	0.004	
filterable + condensable	0.03	
2. NO_x*		

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

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

Pollutant	grains/dscf	ppmdv (3% O_2)
68^{O}F, 29.92 in Hg		
~~1.~~ [~~Units #1, #2 and #3~~ ~~(i) PM10~~		
~~filterable~~	~~0.029~~	
~~filterable + condensable~~	~~0.29~~	
~~2.~~]Unit #4		
(i) PM_{10}		
filterable	0.029	
filterable + condensable	0.29	

(ii) NO_x*

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

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

Pollutant	Test Frequency	Initial Test
1. PM_{10}	every year	#

Initial testing shall be performed when burning natural gas and also when burning coal as fuel. The initial test date 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.

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

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

~~Pollutant~~	~~grains/dscf 68°F, 29.92 in Hg~~	~~ppmdv (3% O_2)~~
~~[1. Units #1, #2, and #3~~		
~~(i) PM_{10} filterable~~	~~0.029~~	
~~(ii) filterable + condensable~~	~~0.29~~	
~~(iii) NO_x Units #1, #2, and #3~~		~~426.5]~~
~~2. Unit #4~~		
~~(i) PM_{10} filterable~~	~~0.029~~	
~~(ii) NO_x*~~		~~[384]~~

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

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

~~Pollutant~~	~~Test Frequency~~
~~1. PM_{10}~~	~~every year~~
~~[2. NO_x~~	~~every year]~~

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

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

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

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

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

ii. Tailings Impoundment

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

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

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

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

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

I. Alert the Utah Division of Air Quality promptly.

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.

Kennecott Utah Copper (KUC): Smelter & Refinery

i. Smelter

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

I. Main Stack (Stack No. 11)

1. PM_{10}
   a. 89.5 lbs/hr (filterable)
   b. 439 lbs/hr (filterable + condensable)

2. SO_2
   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

C. KUC must operate and maintain the 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.

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.

j. PacifiCorp Energy: Gadsby Power Plant

i. Steam Generating Unit #1:

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

B. Emissions of NO_x shall not exceed 336 ppmvd (@ 3% O_2, dry)

C. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO_x and O_2 monitors to determine compliance with the NO_x limitation. The CEM shall operate as outlined in IX.H.1.f.

ii. Steam Generating Unit #2:

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

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

C. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_x and O_2 monitors to determine compliance with the NO_x limitation.

iii. Steam Generating Unit #3:

A. Emissions of NO_x shall be no greater than

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

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

II. Emissions of NO_x shall not exceed 168 ppmvd (@ 3% O_2, dry)[~~, applicable between November 1 and February 28/29~~].

C. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO_x and O_2 monitors to determine compliance with the NO_x limitation. The CEM shall operate as outlined in IX.H.1.f.

iv. Steam Generating Units #1-3:

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

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

A. Total emissions of NO_x from all three turbines shall be no greater than 600 lbs/day. 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. Emissions of NO_x from each turbine stack shall not exceed 5 ppmvd (@ 15% O_2 , dry). Emissions shall be calculated on a 30-day rolling average. This limitation applies to steady state operation, not including startup and shutdown.

C. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO_x and O_2 monitors to determine compliance with the NO_x limitation. The CEM shall operate as outlined in IX.H.1.f.

vi. Combustion Turbine Startup / Shutdown Emission Minimization Plan

A. Startup begins when the fuel values open and natural gas is supplied to the combustion turbines

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

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

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

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

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

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

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

k. Tesoro Refining & Marketing Company

i. Source-wide PM_{10} Cap
No later than January 1, 2019, combined emissions of PM_{10} shall not exceed 2.25 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.k.i.B below, the default emission factors to be used are as follows:

Natural gas:
Filterable PM_{10}: 0.0019 lb/MMBtu
Condensable PM_{10}: 0.0056 lb/MMBtu

Plant gas:
Filterable PM_{10}: 0.0019 lb/MMBtu
Condensable PM_{10}: 0.0056 lb/MMBtu

Fuel Oil: The PM_{10} emission factor shall be determined from the latest edition of AP-42

Cooling Towers: The PM_{10} emission factor shall be determined from the latest edition of AP-42

FCC Wet Scrubber:
The PM_{10} emission factors shall be based on the most recent stack test and verified by parametric monitoring as outlined in IX.H.1.g.i.B.III

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

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

Initial PM_{10} stack testing on the FCC wet gas scrubber stack shall be conducted no later than January 1, 2019 and at least [~~once every three (3) years thereafter~~]annually hereafter. Stack testing shall be performed as outlined in IX.H.1.e.

Results from any stack testing performed at any other PM_{10} sources in accordance with IX.H.1.e shall be used where available.

C. Compliance with the Source-wide PM_{10} Cap shall be determined for each day as follows:

Total 24-hour PM_{10} emissions for the emission points shall be calculated by adding the daily results of the PM_{10} emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers and wet scrubber to arrive at a combined daily PM_{10} 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.

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

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

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

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.k.ii.B below, the default emission factors to be used are as follows:

Natural gas/refinery fuel gas combustion using: Low NO_x burners (LNB): 0.051 lbs/MMbtu
Ultra-Low NO_x (ULNB) burners: 0.04 lbs/MMbtu
Diesel fuel: shall be determined from the latest edition of AP-42

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

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

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

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

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

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.

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

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

iii. Source-wide SO_2 Cap
No later than January 1, 2019, combined emissions of SO_2 shall not exceed 3.8 tons per day (tpd) and 300 tons per rolling 12-month period.

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. The default emission factors to be used are as follows:

Natural gas: EF = 0.0006 lb/MMBtu
Propane: EF = 0.0006 lb/MMBtu
Diesel fuel: shall be determined from the latest edition of AP-42

Plant fuel gas: the emission factor shall be calculated from the H_2S measurement or from the SO_2 measurement obtained by direct testing/monitoring.

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

B. Compliance with the source-wide SO_2 Cap shall be determined for each day as follows: Total daily SO_2 emissions shall be calculated by adding the daily SO_2 emissions for natural gas, plant fuel gas, and propane combustion to those from the wet gas scrubber stack, and SRU.

Daily SO_2 emissions from the FCCU wet gas scrubber stack shall be determined by multiplying the SO_2 concentration in the flue gas by the flow rate of the flue gas. The SO_2 concentration in the flue gas shall be determined by a CEM as outlined in IX.H.1.f.

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

Daily SO_2 emissions from other affected units shall be determined by multiplying the quantity of each fuel used daily at each affected unit by the appropriate emission factor.

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 H_2S (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.

C. Instead of complying with Condition IX.H.1.g.ii.A, sources may reduce the H_2S content of the refinery plant gas to 60 ppm or less or reduce SO_2 concentration from fuel gas combustion devices to 8 ppmvd at 0% O_2 or less as described in 40 CFR 60.102a. Compliance shall be based on a rolling average of 365 days. The owner/operator shall comply with the fuel gas or SO_2 emissions monitoring requirements of 40 CFR 60.107a and the related recordkeeping and reporting requirements of 40 CFR 60.108a. As used herein, refinery “plant gas” shall have the meaning of “fuel gas” as defined in 40 CFR 60.101a, and may be used interchangeably.

iv. SO_2 emissions from the SRU/TGTU/TGI shall be limited to:

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

C. 0.69 tpd for the remainder of the rolling 12-month period.

D. Daily sulfur dioxide emissions from the SRU/TGI/TGTU shall be determined by multiplying the SO_2 concentration in the flue gas by the mass flow of the flue gas. The sulfur dioxide concentration in the flue gas shall be determined by CEM as outlined in IX.H.1.f

v. 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.

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)

l. University of Utah: University of Utah Facilities

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

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

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

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

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~~] 20	every year#
D. Turbine	NO_X	*	every year#
E. Turbine and WHRU Duct burner	NO_X	*	every year#

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

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

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 potable 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.~~]

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

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

ii. Emissions of NO_x shall not exceed 5ppmdv (@ 15% O_2, dry) on a 30-day rolling average.

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

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

H.4 Interim Emission Limits and Operating Practices

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

b. Petroleum Refineries:

i. All petroleum refineries in or affecting the PM_{10} nonattainment/maintenance area shall, for the purpose of this PM_{10} Maintenance Plan:

A. Achieve an emission rate equivalent to no more than 9.8 kg of SO_2 per 1,000 kg of coke burn- off from any Catalytic Cracking unit by use of low-SO_x catalyst or equivalent emission reduction techniques or procedures, including those outlined in 40 CFR 60, Subpart J. Unless otherwise specified in IX.H.2, compliance shall be determined for each day based on a rolling seven-day average.

B. Compliance Demonstrations.

I. Compliance with the maximum daily (24-hr) plant-wide emission limitations for PM_{10}, SO_2, and NO_x shall be determined by adding the calculated emission estimates for all fuel burning process equipment to those from any stack-tested or CEM-measured source components. NO_x and PM_{10} emission factors shall be determined from AP-42 or from test data.

For SO_x, the emission factors are:

Natural gas: EF = 0.60 lb/MMscf
Propane: EF = 0.60 lb/MMscf
Plant gas: the emission factor shall be calculated from the H_2S measurement required in IX.H.1.g.ii.A.

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

EF (lb SO_2/k gal) = density (lb/gal) * (1000 gal/k gal) * wt.% S/100 * (64 lb SO_2/32 lb S)

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

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.

c. Big West Oil Company

i. PM_{10} Emissions

A. Combined emissions of filterable PM_{10} from all external combustion process equipment shall not exceed the following:

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

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

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

The daily primary PM_{10} contribution from the Catalyst Regeneration System shall be calculated using the following equation:

Emitted PM_{10} = (Feed rate to FCC in kbbl/time) * (22 lbs/kbbl)

wherein the emission factor (22 lbs/kbbl) may be re-established by stack testing. Total 24-hour PM_{10} emissions shall be calculated by adding the daily emissions from the external combustion process equipment to the estimate for the Catalyst Regeneration System.

ii. SO_2 Emissions

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

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

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

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

The daily SO_2 emission from the Catalyst Regeneration System shall be calculated using the following equation:

SO_2 = [43.3 lb SO_2/hr / 7,688 bbl feed/day] x [(operational feed rate in bbl/day) x (wt% sulfur in feed / 0.1878 wt%) x (operating hr/day)]

The FCC feed weight percent sulfur concentration shall be determined by the refinery laboratory every 30 days with one or more analyses. Alternatively, SO_2 emissions from the Catalyst Regeneration System may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

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

Total 24-hour SO_2 emissions shall be calculated by adding the daily emissions from the external combustion process equipment to the values for the Catalyst Regeneration System and the SRU.

iii. NO_x Emissions

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

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

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

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

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

NO_x = (Flue Gas, moles/hr) x (180 ppm /1,000,000) x (30.006 lb/mole) x (operating hr/day)

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

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

d. Chevron Products Company

i. PM_{10} Emissions

A. Combined emissions of filterable PM_{10} from all external combustion process equipment shall be no greater than 0.234 tons per day.

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

ii. SO_2 Emissions

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

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

Alternatively, SO_2 emissions from the FCC CO Boiler and Catalyst Regenerator may be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

iii. NO_x Emissions

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

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

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

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

e. Holly Refining and Marketing Company

i. PM_{10} Emissions

A. Combined emissions of filterable PM_{10} from all combustion sources, shall be no greater than 0.44 tons per day.

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

ii. SO_2 Emissions

A. Combined emissions of SO_2 from all sources shall be no greater than 4.714 tons per day.

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

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

iii. NO_x Emissions:

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

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

f. Tesoro Refining & Marketing Company

i. PM_{10} Emissions

A. Combined emissions of filterable PM_{10} from gas-fired compressor drivers and all external combustion process equipment, including the FCC/CO Boiler (ESP), shall be no greater than 0.261 tons per day.

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

ii. SO_2 Emissions

A. Combined emissions of SO_2 from gas-fired compressor drivers and all external combustion process equipment, including the FCC/CO Boiler (ESP), shall not exceed[~~ the following:~~

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

[~~II. March 1 through October 31: 4.374 tons/day.~~]

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

Emissions from the ESP stack (FCC/CO Boiler) shall be determined by multiplying the SO_2 concentration in the flue gas by the mass flow of the flue gas.

The SO_2 concentration in the flue gas shall be determined by a continuous emission monitor (CEM).

iii. NO_x Emissions

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

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

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

a. Except as otherwise outlined in individual conditions of this Subsection IX.H.11 listed below, the terms and conditions of this Subsection IX.H.11 shall apply to all sources subsequently addressed in Subsection IX.H.12 and 13. Should any inconsistencies exist between these subsections, the source specific conditions listed in IX.H.12 and 13 shall take precedence.

b. Definitions:

i. The definitions contained in R307-101-2, Definitions, apply to Section IX, Part H.

ii. Natural gas curtailment means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment.

c. Recordkeeping and Reporting:

i. Any information used to determine compliance shall be recorded for all periods when the source is in operation, and such records shall be kept for a minimum of five years. Any or all of these records shall be made available to the Director upon request.

ii. Each source shall comply with all applicable sections of R307-150 Emission Inventories. iii. Each source shall submit a report of any deviation from the applicable requirements of this Subsection IX.H, including those attributable to upset conditions, the probable cause of such deviations, and any corrective actions or preventive measures taken. The report shall be submitted to the Director no later than 24-months following the deviation or earlier if specified by an underlying applicable requirement. Deviations due to breakdowns shall be reported according to the breakdown provisions of R307-107.

d. Emission Limitations:

i. All emission limitations listed in Subsections IX.H.12 and IX.H.13 apply at all times, unless otherwise specified in the source specific conditions listed in IX.H.12 and 13.

ii. All emission limitations of particulate matter ($PM_{2.5}$) listed in Subsections IX.H.12 and IX.H.13 include both filterable $PM_{2.5}$ and condensable PM, unless otherwise specified in the source specific conditions listed in IX.H.12 and IX.H.13.

e. Stack Testing:

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 "SO_2 Removal & PM, SO_2, 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. SO_2: 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 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

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 an affected 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

A. FCCU SO_2 Emissions

I. Each owner or operator of an FCCU shall comply with an SO_2 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 coke 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) to measure PM emissions on the

FCCU. Each owner operator shall conduct stack tests [~~once every [five]three 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 for determination of source-wide $PM_{2.5}$ 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 PM_{10} nonattainment or maintenance area shall reduce the H_2S content of the refinery plant gas to 60 ppm or less as described in 40 CFR 60.102a. Compliance shall be based on a rolling average of 365 days. The owner/operator shall comply with the fuel gas monitoring requirements of 40 CFR 60.107a and the related recordkeeping and reporting requirements of 40 CFR 60.108a. As used herein, refinery "plant gas" shall have the meaning of "fuel gas" as defined in 40 CFR 60.101a, and may be used interchangeably.

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

iii. Limits on Heat Exchangers

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

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

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

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

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

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

iv. Leak Detection and Repair Requirements

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

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

v. Requirements on Hydrocarbon Flares

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

B. No later than January 1, 2019, all major source petroleum refineries in or affecting any $PM_{2.5}$ nonattainment area or any PM_{10} nonattainment or maintenance area shall either 1) install and operate a flare gas recovery system designed to limit hydrocarbon flaring produced from each affected flare during normal operations to levels below the values listed in 40 CFR 60.103a(c), or 2) limit flaring during normal operations to 500,000 scfd for each affected flare. Flare gas recovery is not required for dedicated SRU flare and header systems, or HF flare and header systems.

vi. Requirements on Tank Degassing

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

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

C. The Director shall be notified of the intent to degas any tank subject to the rule. Except in an emergency situation, initial notification shall be submitted at least three (3) days prior to degassing operations. The initial notification shall include:

I. Start date and time;

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

III. Degassing operator’s name, contact person, telephone number;

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

V. Description of vapor control device.

vii. No Burning of Liquid Fuel Oil in Stationary Sources

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

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

h. Catalytic Oxidation for VOC Control

i. Internal Combustion Engines

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

ii. Natural Gas Combustion Turbines

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

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

a. ATK Launch Systems Inc. Promontory

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

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

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

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

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

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

iii. Natural Gas-Fired Boilers

A. Building M-576

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

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% O_2 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% O_2 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. Big West Oil Refinery

i. Source-wide $PM_{2.5}$:

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

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.12.b.i.B below, the default emission factors to be used are as follows:

Natural gas:
Filterable $PM_{2.5}$: 1.9 lb/MMscf
Condensable $PM_{2.5}$: 5.7 lb/MMscf

Plant gas:
Filterable $PM_{2.5}$: 1.9 lb/MMscf
Condensable $PM_{2.5}$: 5.7 lb/MMscf

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

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

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

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

$PM_{2.5}$ stack testing on the FCC shall be performed initially 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.11.e.

C. Compliance with the source-wide $PM_{2.5}$ Cap shall be determined for each day as follows: Total 24-hour $PM_{2.5}$ emissions for the emission points shall be calculated by adding the daily results of the $PM_{2.5}$ emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the FCC to arrive at a combined daily $PM_{2.5}$ 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 gas consumption shall be measured by meters that can delineate the flow of gas to the boilers, furnaces and the SRU incinerator.

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

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

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

Where:
E = Emitted $PM_{2.5}$
FR = Feed Rate to Unit (kbbls/day)
EF = emission factor (lbs/kbbl), established by the most recent stack test

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

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

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.12.b.ii.B below, the default emission factors to be used are as follows:

Natural gas: shall be determined from the latest edition of AP-42
Plant gas: assumed equal to natural gas
Diesel fuel: shall be determined from the latest edition of AP-42

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

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

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

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

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

NO_x = Emission Factor (lb/MMscf)*Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton)

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

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

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

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

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

iii. Source-wide SO_2 Cap

No later than January 1, 2019, combined emissions of SO_2 shall not exceed 0.60 tons per day and 140 tons per rolling 12-month period.

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. The default emission factors to be used are as follows:

Natural Gas - 0.60 lb SO_2/MMscf gas

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

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

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

EF (lb SO_2/k gal) = density (lb/gal) * (1000 gal/k gal) * wt. % S/100 * (64 lb SO_2/32 lbs)

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

B. Compliance with the source-wide SO_2 Cap shall be determined for each day as follows:
Total daily SO_2 emissions shall be calculated by adding the daily SO_2 emissions for natural gas and plant fuel gas combustion, to those from the FCC and SRU stacks.

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

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.

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

Results shall be tabulated for each day, and records shall be kept which include CEM readings for H_2S (averaged for each day), all meter readings (in the appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel oil is burned), and the calculated emissions.

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 SO_2 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.

c. Chemical Lime Company (LHoist North America)

Lime Production Kiln

i. No later than January 1, 2019, or upon source start-up, whichever comes later, SNCR technology shall be installed on the Lime Production Kiln.

a. Effective January 1, 2019, or upon source start-up, whichever comes later, NO_X emissions shall not exceed 56 lb/hr. (3-hr rolling average)

b. Compliance with the above emissions limit shall be determined by stack testing as outlined in Section IX Part H.11.e of this SIP.

ii. No later than January 1, 2019, or upon source start-up, whichever comes later, a baghouse control technology shall be installed and operating on the Lime Production Kiln.

a. Effective January 1, 2019, or upon source start-up, whichever comes later, PM emissions shall not exceed 0.12 pounds per ton (lb/ton) of stone feed. (3-hr rolling average)

b. Effective January 1, 2019, or upon source start-up, whichever comes later, $PM_{2.5}$ (filterable + condensable) emissions shall not exceed 1.5 lbs/ton of stone feed. (3-hr rolling average)

c. Compliance with the above emission limits shall be determined by stack testing as outlined in Section IX Part H.11.e of this SIP and in accordance with 40 CFR 63 Subpart AAAAA.

iii. An initial compliance test is required no later than January 1, 2019 (if start-up occurs on or before January 1, 2019) or within 180 days of source start-up (if start-up occurs after January 1, 2019) ***All subsequent compliance testing shall be performed at least once annually based upon the date of the last compliance test.***

iv. Upon plant start-up kiln emissions shall be exhausted through the baghouse during all startup, shutdown, and operations of the kiln.

v. Start-up/shut-down provisions for SNCR technology be as follows:

a. No ammonia or urea injection during startup until the combustion gases exiting the kiln reach the temperature when NO_X reduction is effective, and

b. No ammonia or urea injection during shutdown.

c. Records of ammonia or urea injection shall be documented in an operations log.

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

d. Chevron Products Company - Salt Lake Refinery

i. Source-wide $PM_{2.5}$ Cap

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

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.12.f.i.B below, the default emission factors to be used are as follows:

Natural gas:
Filterable $PM_{2.5}$: 1.9 lb/MMscf
Condensable $PM_{2.5}$: 5.7 lb/MMscf

Plant gas:
Filterable $PM_{2.5}$: 1.9 lb/MMscf
Condensable $PM_{2.5}$: 5.7 lb/MMscf

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

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

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

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

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

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

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

Total 24-hour $PM_{2.5}$ emissions for the emission points shall be calculated by adding the daily results of the $PM_{2.5}$ emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the FCC to arrive at a combined daily $PM_{2.5}$ 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.

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

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

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

ii. Source-wide NO_x Cap

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

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.12.f.ii.B below, the default emission factors to be used are as follows:

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

Plant gas: assumed equal to natural gas

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

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

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

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

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

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

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

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

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.

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 the meter readings (in the appropriate units) and the calculated emissions

iii. Source-wide SO_2

No later than January 1, 2019, combined emissions of SO_2 shall not exceed 1.05 tons per day (tpd) and 383.3 tons per rolling 12-month period.

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. The default emission factors to be used are as follows:

FCC: The emission rate shall be determined by the FCC SO_2 CEM as outlined in IX.H.11.f.

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

Natural gas: EF = 0.60 lb/MMscf

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

EF (lb SO_2/k gal) = density (lb/gal) * (1000 gal/k gal) * wt.% S/100 * (64 lb SO_2/32 lb S)

Plant gas: the emission factor shall be calculated from the H_2S measurement obtained from the H_2S CEM.

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

B. Compliance with the source-wide SO_2 Cap shall be determined for each day as follows: Total daily SO_2 emissions shall be calculated by adding the daily SO_2 emissions for natural gas and plant fuel gas combustion, to those from the FCC and SRU stacks.

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 H_2S (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 and Alternative Fuels

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

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

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

v. Compressor Engine Requirements

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

Engine Number	NO_x in ppmvd @ 0% O_2
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 years thereafter~~]annually. Stack testing shall be performed as outlined in IX.H.11.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.11.g.v.B

18)

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**
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)

e. Compass Minerals Ogden Inc.

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

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

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

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

Emission Unit	$PM_{2.5}$ Emission Rate (lb/hr)	Concentration Emission Rate (grains/dscf)
AH-500	1.61	0.01
AH-502	0.7[~~5~~]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~~]4.25	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.[~~40~~]39	0.01
BH-1400	2.78	0.02
AH-692	0.12	0.01
BH-1516	0.22	0.01

A. Compliance to the above emission limits shall be determined by stack test as outlined in Section IX Part H.11.e of this SIP. Compliance testing shall be performed [~~at least once every three years~~]annually.

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

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

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

~~years~~]annually.

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

f. 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 to 16, the line's baghouse(s) and natural gas injection dual chambered regenerative thermal oxidizer 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.

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

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

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

	Concentration (ppm)
Fiber Line 3	9.0
Fiber Line 4	9.0

Fiber Line 7 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 / Qmax

Where
R = residence time
V = interior volume of the incinerator – ft3
Qmax = 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.

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

i. Source-wide $PM_{2.5}$ Cap

No later than January 1, 2019, $PM_{2.5}$ emissions (filterable + condensable) from all combustion sources shall not exceed 47.6 tons per rolling 12-month period and 0.134 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.12.i.i.B below, the default emission factors to be used are as follows:

Natural gas or Plant gas:
non-NSPS combustion equipment: 7.65 lb $PM_{2.5}$/MMscf
NSPS combustion equipment: 0.52 lb $PM_{2.5}$/MMscf

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

$PM_{2.5}$ (lb/1000 gal) = (10 * wt. % S) + 3

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

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

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

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

C. Compliance with the source-wide $PM_{2.5}$ Cap shall be determined for each day as follows: Total 24-hour $PM_{2.5}$ emissions for the emission points shall be calculated by adding the daily results of the $PM_{2.5}$ emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the wet scrubbers to arrive at a combined daily $PM_{2.5}$ 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.12.i.ii.B below, the default emission factors to be used are as follows:

Natural gas/refinery fuel gas combustion using:
Low NO_x burners (LNB): 41 lbs/MMscf
Ultra-Low NO_x (ULNB) burners: 0.04 lbs/MMbtu
Next Generation Ultra Low NO_x burners (NGULNB): 0.10 lbs/MMbtu

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

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

All fuel oil combustion: 120 lbs/Kgal

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

C. Compliance with the Source-wide NO_x Cap shall be determined for each day as follows: Total daily NO_x emissions for emission points shall be calculated by adding the results of the NO_x equations for plant gas, fuel oil, and natural gas combustion listed below. 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.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply 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 Gas Consumption (MMscf/day)/(2,000 lb/ton)

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

Emissions (tons/day) = Emission Factor (lb/MMBTU) * Burner Heat Rating (BTU/hr)* 24 hours per 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 the meter readings (in the appropriate units), emission factors, and the calculated emissions.

iii. Source-wide SO_2 Cap

No later than January 1, 2019, the emission of SO_2 from all emission points (excluding routine SRU turnaround maintenance emissions) shall not exceed 110.3 tons per rolling 12- month period and 0.31 tons per day (tpd).

A. Setting of emission factors:
The emission factors listed below shall be applied to the relevant quantities of fuel combusted:

Natural gas - 0.60 lb SO_2/MMscf

Plant gas - The emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a CEM which will measure the H_2S content of the fuel gas. The CEM shall operate as outlined in IX.H.11.f.

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

(lb of SO_2/kgal) = (density lb/gal) * (1000 gal/kgal) * (wt. %S)/100 * (64 g SO_2/32 g S)

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

B. Compliance with the Source-wide SO_2 Cap shall be determined for each day as follows: Total daily SO_2 emissions shall be calculated by adding daily results of the SO_2 emissions
equations listed below for natural gas, plant gas, and fuel oil combustion. For purposes
of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

The equations used to determine emissions are:

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

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

Emissions (tons/day) = Emission Factor (lb/kgal) * 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 H_2S (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.

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**
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)

h. Kennecott Utah Copper (KUC): Mine

i. Bingham Canyon Mine (BCM)

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

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

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

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

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

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

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

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

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

ii. Copperton Concentrator (CC)

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

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

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

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.

j. Kennecott Utah Copper (KUC): Power Plant

i. Utah Power Plant

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

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

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

Pollutant	grains/dscf 68°F. 29.92 in Hg	ppmdv 3% O_2	lbs/hr	lbs/MMBtu	lbs/event
1. $PM_{2.5}$:					
Filterable	0.004				
Filterable + condensable	0.03				
2. NO_x:		20	17.0	0.02	
Startup / Shutdown					395

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

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

~~Pollutant~~	~~grains/dscf 68°F. 29.92 in Hg~~	~~ppmdv~~	~~lbs/hr~~	~~lbs/MMBTU 3% O_2~~	~~lbs/event~~
~~1. $PM_{2.5}$:~~					
~~Filterable~~	~~0.029~~				
~~Filterable + condensable~~	~~0.29~~				
~~2. NO_x:~~		~~80~~		~~0.06~~	
~~Startup / Shutdown~~					~~395~~

~~* Except during startup and shutdown.~~

~~3. SO_2:~~			~~290~~		~~0.34~~

~~V.~~]Startup / Shutdown Limitations:

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

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

3. Definitions:

(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.

B. Upon commencement of operation of Unit #4, stack testing to demonstrate compliance with each emission limitation-in IX.H.12.[~~k~~]j.i.A and IX.H.12. [~~k~~]j.i.B shall be performed as follows:

* Initial compliance testing for the Unit 4 boiler is required. Initial testing shall be performed when burning natural gas[~~ and also when burning coal as fuel~~]. 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. [NH_4]~~SO_2	~~every year~~]

C. Unit #5 (combined cycle, natural gas-fired combustion turbine) shall not exceed the following emission rates to the atmosphere:

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:			2.0*
Startup / Shutdown	395		

* Except during startup and shutdown.

IV. Startup / Shutdown Limitations:

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

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

3. Definitions:

(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

j. Kennecott Utah Copper: Smelter and Refinery

i. Smelter:

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

I. Main Stack (Stack No. 11)

1. $PM_{2.5}$
   a. 85 lbs/hr (filterable)
   b. 434 lbs/hr (filterable + condensable)

2. SO_2
   a. 552 lbs/hr (3 hr. rolling average)
   b. 422 lbs/hr (daily average)

3. NO_x 154 lbs/hr (daily average)

II. Holman Boiler

1. NO_x
   a. 14 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)	$PM_{2.5}$	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

The Holman boiler shall use an EPA approved test method [~~every three years and in-between years use~~]annually or an approved CEMS or alternate method according to applicable NSPS standards.

C. During startup/shutdown operations, NO_x and SO_2 emissions are monitored by CEMS or alternate methods in accordance with applicable NSPS standards.

D. KUC must operate and maintain the 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.

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 (before December 2020)
(Upgraded Tankhouse Boiler)	NO_x	1.5 lbs/hr (After December 2020)
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
Upgraded 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 more than 300 hours during a three year period.~~]

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

D. 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. Records shall be kept on site which indicate the date and time of startups and shutdowns.

k. Nucor Steel Mills

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

A. Electric Arc Furnace Baghouse

I. $PM_{2.5}$
1. 17.4 lbs/hr (24 hr. average filterable)
2. 29.53 lbs/hr (24 hr. average condensable)

II. SO_2
1. 93.98 lbs/hr (3 hr. rolling average)
2. 89.0 lbs/hr (daily average)

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

IV. VOC 22.20 lbs/hr

B. Reheat Furnace #1
NO_x 15.0 lb/hr

C. Reheat Furnace #2
NO_x 8.0 lb/hr

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

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

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

A. To demonstrate compliance with the Electric Arc Furnace stack mass emissions limits for SO_2 and NO_x of Condition (i)(A) above, Nucor shall calibrate, maintain and operate the measurement systems for continuously monitoring for SO_2 and NO_x concentrations and stack gas volumetric flow rates in the Electric Arc Furnace stack. Such measurement systems shall meet the requirements of R307-170.

B. For $PM_{2.5}$ testing, 40 CFR 60, Appendix A, Method 5D, or another EPA approved method acceptable to the Director, shall be used to determine total TSP emissions. If TSP emissions are below the $PM_{2.5}$ limit, that will constitute compliance with the $PM_{2.5}$ limit. If TSP emissions are not below the $PM_{2.5}$ limit, the owner/operator shall retest using EPA approved methods specified for PM2.5 testing, within 120 days.

C. Startup/shutdown NO_x and SO_2 emissions are monitored by CEMS.

l. PacifiCorp Energy: Gadsby Power Plant

i. Steam Generating Unit #1:

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

B. Emissions of NOx shall not exceed 336 ppmdv (@ 3% O2, dry)

C. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO_x and O_2 monitors to determine compliance with the NO_x limitation. The CEM shall operate as outlined in IX.H.11.f.

ii. Steam Generating Unit #2:

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

B. Emissions of NOx shall not exceed 336 ppmdv (@ 3% O2, dry)

C. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_x and O_2 monitors to determine compliance with the NO_x limitation.

iii. Steam Generating Unit #3:

A. Emissions of NO_x shall be no greater than

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

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

B. Emissions of NOx shall not exceed

I. 168 ppmdv (@ 3% O2, dry)[~~, applicable between November 1 and February 28/29~~

II. ~~168 ppmdv (@ 3% O2, dry), applicable between applicable between March 1 and October 31~~].

C. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO_x and O_2 monitors to determine compliance with the NO_x limitation. The CEM shall operate as outlined in IX.H.11.f.

iv. Steam Generating Units #1-3:

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

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

A. Total emissions of NO_x from all three turbines shall be no greater than 600 lbs/day. 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. Emissions of NOx from each turbine stack shall not exceed 5 ppmvd (@ 15% O2 dry). Emissions shall be calculated on a 30-day rolling average. This limitation applies to steady state operation, not including startup and shutdown.

C. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO_x and O_2 monitors to determine compliance with the NO_x limitation. The CEM shall operate as outlined in IX.H.11.f.

vi. Combustion Turbine Startup / Shutdown Emission Minimization Plan

A. Startup begins when the fuel values open and natural gas is supplied to the combustion turbines

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

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

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

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

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

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

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

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

i. Source-wide $PM_{2.5}$ Cap

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

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.12.p.i.B below, the default emission factors to be used are as follows:

Natural gas:
Filterable $PM_{2.5}$: 0.0019 lb/MMBtu
Condensable $PM_{2.5}$: 0.0056 lb/MMBtu

Plant gas:
Filterable $PM_{2.5}$: 0.0019 lb/MMBtu
Condensable $PM_{2.5}$: 0.0056 lb/MMBtu

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

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

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

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

Initial $PM_{2.5}$ stack testing on the FCC wet gas scrubber stack shall be conducted 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.11.e.

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

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

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

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

ii. Source-wide NO_x Cap

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

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.12.m.ii.B below, the default emission factors to be used are as follows:

Natural gas/refinery fuel gas combustion using:
Low NO_x burners (LNB):0.051 lbs/MMbtu
Ultra-Low NO_x (ULNB) burners: 0.04 lbs/MMbtu
Diesel fuel: shall be determined from the latest edition of AP-42

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

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

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

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

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.

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

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

iii. Source-wide SO_2 Cap

No later than January 1, 2019, combined emissions of SO_2 shall not exceed 3.8 tons per day (tpd) and 300 tons per rolling 12-month period.

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. The default emission factors to be used are as follows:

Natural gas: EF = 0.0006 lb/MMBtu
Propane: EF = 0.0006 lb/MMBtu
Diesel fuel: shall be determined from the latest edition of AP-42

Plant fuel gas: the emission factor shall be calculated from the H_2S measurement or from the SO_2 measurement obtained by direct testing/monitoring.

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

B. Compliance with the source-wide SO_2 Cap shall be determined for each day as follows: Total daily SO_2 emissions shall be calculated by adding the daily SO_2 emissions for natural gas, plant fuel gas, and propane combustion to those from the wet gas scrubber stack.

Daily SO_2 emissions from the FCCU wet gas scrubber stack shall be determined by multiplying the SO_2 concentration in the flue gas by the flow rate of the flue gas. The SO_2 concentration in the flue gas shall be determined by a CEM as outlined in IX.H.11.f.

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

Daily SO_2 emissions from other affected units shall be determined by multiplying the quantity of each fuel used daily at each affected unit by the appropriate emission factor.

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 H_2S (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.

C. Instead of complying with Condition IX.H.11.g.ii.A, source may reduce the H_2S content of the refinery plant gas to 60 ppm or less or reduce SO_2 concentration from fuel gas combustion devices to 8 ppmvd at 0% O_2 or less as described in 40 CFR 60.102a. Compliance shall be based on a rolling average of 365 days. The owner/operator shall comply with the fuel gas or SO_2 emissions monitoring requirements of 40 CFR 60.107a and the related recordkeeping and reporting requirements of 40 CFR 60.108a. As used herein, refinery "plant gas" shall have the meaning of "fuel gas" as defined in 40 CFR 60.101a, and may be used interchangeably.

iv. SO_2 emissions from the SRU/TGTU/TGI shall be limited to:

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

B. 0.69 tpd for the remainder of the rolling 12-month period.

C. Daily sulfur dioxide emissions from the SRU/TGI/TGTU shall be determined by multiplying the SO_2 concentration in the flue gas by the mass flow of the flue gas. The sulfur dioxide concentration in the flue gas shall be determined by CEM as outlined in IX.H.11.f

v. 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.

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)

n. The Procter & Gamble Paper Products Company

i. Emissions to the atmosphere at all times from the indicated emission points shall not exceed the following rates:

Source: Paper Making Boilers (Each)

Pollutant	Oxygen Ref.	lb/hr
NOx	3%	3.3
$PM_{2.5(\text{Filterable and Condensables})}$	3%	0.9

Source: Paper Machine Process Stack

Pollutant	Oxygen Ref.	lb/hr
NO_X	3%	13.50
$PM_{2.5(\text{Filterable and Condensables})}$	3%	17.95

Source: Utility Boilers (Each)

Pollutant	Oxygen Ref.	lb/hr
NO_X	3%	1.8
$PM_{2.5(\text{Filterable and Condensables})}$)	3%	0.74

A. Compliance with the above emission limits shall be determined by stack test as outlined in Section IX Part H.11.e of this SIP.

B. Subsequent to initial compliance testing, stack testing is required [~~at a minimum of every three years~~]annually.

ii. Boiler Startup/Shutdown Emissions Minimization Plan

A. Startup begins when natural gas is supplied to the Boiler(s) with the intent of combusting the fuel to generate steam. Startup conditions end within thirty (30) minutes of natural gas being supplied to the boilers(s).

B. Shutdown begins with the initiation of the stop sequence of the boiler until the cessation of natural gas flow to the boiler.

iii. Paper Machine Startup/Shutdown Emissions Minimization Plan

A. Startup begins when natural gas is supplied to the dryer combustion equipment with the intent of combusting the fuel to heat the air to a desired temperature for the paper machine. Startup conditions end within thirty (30) minutes of natural gas being supplied to the dryer combustion equipment.

B. Shutdown begins with the diversion of the hot air to the dryer startup stack and then the cessation of natural gas flow to the dryer combustion equipment. Shutdown conditions end within thirty (30) minutes of hot air being diverted to the dryer startup stack.

o. University of Utah: University of Utah Facilities

i Emissions to the atmosphere from the listed emission points in Building 303 LCHWTP shall not exceed the following concentrations:

Emissions Point	Pollutant	ppmdv (3% O_2 dry)
Boiler #4*	NO_X	187
Boilers #6 & 7	NO_X	9
Boiler #9*	NO_X	9
Turbine	NO_X	9
Turbine and WHRU Duct burner	NO_X	15

*[~~Boiler #4~~]B December 31, 2019, Boiler #4 will be decommissioned and Boiler #9 will be installed and operational.

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

Emissions Point	Pollutant	Initial Test	Test Frequency
Boiler~~s~~ #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

Initial test already performed

* Initial tests have been performed and the next method test using EPA approved test methods shall be performed within [~~3~~]one year[~~s~~] of the last stack test. Initial compliance testing for Boiler #9 is required. The initial test date 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.

A compliance test shall be performed at least [~~once every three years from the date of the last compliance test that demonstrated compliance with the emission limit(s)~~]annually. Compliance testing shall be performed using EPA approved test methods acceptable to the Director. The Director shall be notified, in accordance with all applicable rules, of any compliance test that is to be performed.

iii. Boiler #4 in the LCHWTP shall be decommissioned and replaced by Boiler #9 by December 31, 2019.

iv. [~~After the second~~]By the end of the third quarter of calendar year 2019, Boilers #1, #3, and #4 in the UCHWTP shall be limited to a natural gas usage of 530 MMscf per calendar year.

v. The HSC Transformation Project boilers shall be installed and operational by the end of the [~~second~~]third quarter of calendar year 2019. The new HSC Transformation Project boilers shall be equipped with low NOx burners rated at 30 ppmvd at 3% O2 or less.

v Records shall be kept on site which indicate the date, and time of startup and shutdown.

p. Utah Municipal Power Association: West Valley Power Plant.

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

ii. Emissions of NO_x shall not exceed 5 ppmdv (@ 15% O_2, dry) on a 30-day rolling average.

iii. Total emissions of NO_X from all five (5) catalytic-controlled turbines shall include the sum of all periods in the day including periods of startup, shutdown, and maintenance.

iv. The NO_X emission rate (lb/hr) shall be determined by CEM. The CEM shall operate as outlined in IX.H.11.f.

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.
