

# **Utah State Implementation Plan**

## **Emission Limits and Operating Practices**

### **Section IX, Part H**

Adopted by the Air Quality Board  
December 7, 2016

## **H.1 General Requirements: Control Measures for Area and Point Sources, Emission Limits and Operating Practices, PM<sub>10</sub> 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<sub>10</sub> 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 IX.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 methods acceptable to the Director.

- B. Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2 or other EPA-approved testing methods acceptable to the Director.
  - C. PM<sub>10</sub>: The following methods shall be used to measure filterable particulate emissions: 40 CFR 51, Appendix M, Method 201 or 201A, or other EPA-approved testing method, as acceptable to the Director. If other approved testing methods are used which cannot measure the PM<sub>10</sub> fraction of the filterable particulate emissions, all of the filterable particulate emissions shall be considered PM<sub>10</sub>.  
The following methods shall be used to measure condensable particulate emissions: 40 CFR 51, Appendix M, Method 202, or other EPA-approved testing method, as acceptable to the Director.
  - D. SO<sub>2</sub>: 40 CFR 60 Appendix A, Method 6C or other EPA-approved testing methods acceptable to the Director.
  - E. NO<sub>x</sub>: 40 CFR 60 Appendix A, Method 7E or other EPA-approved testing methods acceptable to the Director.
  - F. 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.
  - G. 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. The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, and Occupational Safety and Health Administration (OSHA) approvable access shall be provided to the test location.
  - H. 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 (FCCU)
    - A. FCCU SO<sub>2</sub> Emissions
      - I. By no later than January 1, 2018, each owner or operator of an FCCU shall comply with an SO<sub>2</sub> 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. By no later than January 1, 2018, each owner or operator of an FCCU shall comply with an emission limit of 1.0 pounds PM per 1000 pounds coke burned on a 3-hour average basis.
      - 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 at each FCCU.
      - III. By 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 PM<sub>10</sub> emissions.
  - ii. Limits on Refinery Fuel Gas.
    - A. All petroleum refineries in or affecting any PM<sub>2.5</sub> nonattainment area or any PM<sub>10</sub> nonattainment or maintenance area shall reduce the H<sub>2</sub>S content of the refinery plant gas to 60 ppm or less as described in 40 CFR 60.102a. Compliance shall be based on a rolling average of 365 days. The owner/operator shall comply with the fuel gas monitoring requirements of 40 CFR 60.107a and the related recordkeeping and reporting requirements of 40 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<sub>10</sub> 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<sub>2</sub> 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<sub>2</sub> 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 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. Beginning January 1, 2018, all hydrocarbon flares at petroleum refineries located in or affecting a designated PM<sub>10</sub> nonattainment area 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 Subpart Ja.

## H.2 Source Specific Emission Limitations in Salt Lake County PM<sub>10</sub> Nonattainment/Maintenance Area

a. Big West Oil Company

i. Source-wide PM<sub>10</sub> Cap

By no later than January 1, 2019, combined emissions of PM<sub>10</sub> 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<sub>10</sub>: 1.9 lb/MMscf

Condensable PM<sub>10</sub>: 5.7 lb/MMscf

Plant gas:

Filterable PM<sub>10</sub>: 1.9 lb/MMscf

Condensable PM<sub>10</sub>: 5.7 lb/MMscf

Fuel Oil: The PM<sub>10</sub> emission factor shall be determined from the latest edition of AP-42

Cooling Towers: The PM<sub>10</sub> emission factor shall be determined from the latest edition of AP-42

FCC Stacks: The PM<sub>10</sub> 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<sub>10</sub> stack testing on the FCC shall be performed initially no later than January 1, 2019 and at least once every three (3) years thereafter. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide PM<sub>10</sub> Cap shall be determined for each day as follows:

Total 24-hour PM<sub>10</sub> emissions for the emission points shall be calculated by adding the daily results of the PM<sub>10</sub> 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<sub>10</sub> 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<sub>10</sub> emissions from the FCC shall be calculated using the following equation:

$$E = FR * EF$$

Where:

E = Emitted PM<sub>10</sub>

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<sub>x</sub> Cap

By no later than January 1, 2019, combined emissions of NO<sub>x</sub> shall not exceed 0.80 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.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<sub>x</sub> stack testing on natural gas/refinery fuel gas combustion equipment above 40 MMBtu/hr has been performed and the next stack test shall be performed within 3 years of the next stack test. At that time a new flow-weighted average emission factor in terms of: lbs/MMbtu shall be derived for each combustion type listed in IX.H.2.a.ii.A above. Stack testing shall be performed as outlined in IX.H.1.e.

- C. Compliance with the source-wide NO<sub>x</sub> Cap shall be determined for each day as follows:

Total 24-hour NO<sub>x</sub> 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:

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

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<sub>x</sub> emissions from the FCC shall be calculated using a CEM as outlined in IX.H.1.f

Total daily NO<sub>x</sub> emissions shall be calculated by adding the results of the above NO<sub>x</sub> 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<sub>2</sub> Cap

By no later than January 1, 2019, combined emissions of SO<sub>2</sub> shall not exceed 0.60 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. The default emission factors to be used are as follows:

Natural Gas - 0.60 lb SO<sub>2</sub>/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:

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

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<sub>2</sub> Cap shall be determined for each day as follows:

Total daily SO<sub>2</sub> emissions shall be calculated by adding the daily SO<sub>2</sub> emissions for natural gas and plant fuel gas combustion, to those from the FCC and SRU stacks.

The daily SO<sub>2</sub> emission from the FCC shall be calculated using the following equation:

$$\text{SO}_2 = \text{FG} * (\text{ADV}/1,000,000) * (64 \text{ lb/mole}) * (\text{operating hours/day}) / (2000 \text{ lb/ton})$$

Where:

FG = Flue Gas in moles/hour

ADV = average daily value from SO<sub>2</sub> 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.

Results shall be tabulated for each day, and records shall be kept which include CEM readings for H<sub>2</sub>S (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. Alternate Startup and Shutdown Requirements

- A. During any day which includes startup or shutdown of the FCCU, combined emissions of SO<sub>2</sub> 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.

- 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<sub>x</sub> / kW-hr
    - B. GT #2 and GT #3 (each TITAN Turbine)  
Exhaust Stack: 7.5 lb NO<sub>x</sub> / 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<sub>x</sub> 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:

$$\text{Emissions (tons/day)} = (\text{Power production in kW-hrs/day}) \times (\text{Emission factor in grams/kW-hr}) \times (1 \text{ lb}/453.59 \text{ g}) \times (1 \text{ ton}/2000 \text{ lbs})$$

- 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.
- B. The NO<sub>x</sub> emission factor for each engine shall be derived from the most recent stack test.
- C. NO<sub>x</sub> 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<sub>10</sub> Cap

By no later than January 1, 2019, combined emissions of PM<sub>10</sub> 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<sub>10</sub>: 1.9 lb/MMscf

Condensable PM<sub>10</sub>: 5.7 lb/MMscf

Plant gas:

Filterable PM<sub>10</sub>: 1.9 lb/MMscf

Condensable PM<sub>10</sub>: 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<sub>10</sub> 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<sub>10</sub> 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. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide PM<sub>10</sub> Cap shall be determined for each day as follows:

Total 24-hour PM<sub>10</sub> emissions for the emission points shall be calculated by adding the daily results of the PM<sub>10</sub> 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<sub>10</sub> 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<sub>x</sub> Cap

By no later than January 1, 2019, combined emissions of NO<sub>x</sub> shall not exceed 2.1 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.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<sub>x</sub> stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr has been performed and shall be conducted at least once every three (3) years from the date of the last stack test. At that time a new flow-weighted average emission factor in terms of: lbs/MMbtu shall be derived for each combustion type listed in IX.H.2.d.ii.A above. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide NO<sub>x</sub> Cap shall be determined for each day as follows:

Total 24-hour NO<sub>x</sub> 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<sub>x</sub> CEM shall be used to calculate daily NO<sub>x</sub> 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<sub>x</sub> 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<sub>2</sub> Cap

By no later than January 1, 2019, combined emissions of SO<sub>2</sub> shall not exceed 1.05 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. The default emission factors to be used are as follows:

FCC: The emission rate shall be determined by the FCC SO<sub>2</sub> 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:

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

Plant gas: the emission factor shall be calculated from the H<sub>2</sub>S measurement obtained from the H<sub>2</sub>S 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<sub>2</sub> Cap shall be determined for each day as follows:

Total daily SO<sub>2</sub> emissions shall be calculated by adding the daily SO<sub>2</sub> 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<sub>2</sub>S (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.

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<sub>10</sub> Cap

By no later than January 1, 2019, PM<sub>10</sub> 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<sub>10</sub>/MMscf

NSPS combustion equipment: 0.52 lb PM<sub>10</sub>/MMscf

Fuel oil:

The filterable PM<sub>10</sub> emission factor for fuel oil combustion shall be determined based on the sulfur content of the oil as follows:

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

The condensable PM<sub>10</sub> emission factor for fuel oil combustion shall be determined from the latest edition of AP-42.

Cooling Towers: The PM<sub>10</sub> emission factor shall be determined from the latest edition of AP-42.

FCC Wet Scrubbers:

The PM<sub>10</sub> 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

B. The default emission factors listed in IX.H.2.g.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. At that time a new flow-weighted average emission factor in terms of: lb PM<sub>10</sub>/MMBtu shall be derived. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide PM<sub>10</sub> Cap shall be determined for each day as follows:

Total 24-hour PM<sub>10</sub> emissions for the emission points shall be calculated by adding the daily results of the PM<sub>10</sub> 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<sub>10</sub> 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<sub>x</sub> Cap

By no later than January 1, 2019, NO<sub>x</sub> emissions into the atmosphere from all emission points shall not exceed 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<sub>x</sub> burners (LNB): 41 lbs/MMscf

Ultra-Low NO<sub>x</sub> (ULNB) burners: 0.04 lbs/MMbtu

Next Generation Ultra Low NO<sub>x</sub> 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<sub>x</sub> Cap shall be determined for each day as follows:

Total daily NO<sub>x</sub> emissions for emission points shall be calculated by adding the results of the NO<sub>x</sub> 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:

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

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

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMBTU)} * \text{Burner Heat Rating (BTU/hr)} * 24 \text{ hours per day} / (2,000 \text{ lb/ton})$$

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

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<sub>2</sub> Cap

By no later than January 1, 2019, the emission of SO<sub>2</sub> from all emission points shall not exceed 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<sub>2</sub>/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<sub>2</sub>S 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:

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

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<sub>2</sub> Cap shall be determined for each day as follows:

Total daily SO<sub>2</sub> emissions shall be calculated by adding daily results of the SO<sub>2</sub> 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<sub>2</sub>S (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.

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 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. 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 cease operations permanently upon commencing operations of Unit #5 (combined-cycle, natural gas-fired combustion turbine).

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

Pollutant	lb/hr	lb/event	ppmdv (15% O <sub>2</sub> dry)
I. PM <sub>10</sub> with duct firing: Filterable + condensable	18.8		
II. NO <sub>x</sub> : Startup/shutdown		395	2.0

III. Startup / Shutdown Limitations:

1. The total number of startups and shutdowns together shall not exceed 690 per calendar year.
2. The NO<sub>x</sub> 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 <sub>10</sub>	every year
II. NO <sub>x</sub>	every year

D. The following requirements are applicable to Units #1, #2, #3, and #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, 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 68°F, 29.92 in. Hg	grains/dscf	ppmdv (3% O <sub>2</sub> )
1. PM <sub>10</sub> Units #1, #2, #3 and #4		
filterable	0.004	
filterable + condensable	0.03	
2. NO <sub>x</sub> : Units #1, #2 and #3 (each)		336
3. NO <sub>x</sub> Unit #4 (Unit 4 after January 1, 2018)		336 60

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 68°F, 29.92 in Hg	grains/dscf	ppmdv (3% O <sub>2</sub> )
1. Units #1, #2 and #3		
(i) PM <sub>10</sub>		
filterable	0.029	
filterable + condensable	0.29	
(ii) NO <sub>x</sub> Units 1, 2 & 3		426.5
2. Unit #4		
(i) PM <sub>10</sub>		
filterable	0.029	
filterable +		

condensable 0.29

(ii) NO<sub>x</sub> 384

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 <sub>10</sub>	every year	#
2. NO <sub>x</sub>	every year	#

# Initial compliance testing is required for Unit #4 after low NO<sub>x</sub> burner installation. 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 Units #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	ppmdv (3% O <sub>2</sub> )
68°F, 29.92 in Hg		
1. Units #1, #2, and #3		
(i) PM <sub>10</sub> filterable	0.029	
(ii) filterable + condensable	0.29	
(iii) NO <sub>x</sub> Units #1, #2, and #3		426.5
2. Unit #4		
(i) PM <sub>10</sub> filterable	0.029	
(ii) NO <sub>x</sub>		384

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 <sub>10</sub>	every year
2. NO <sub>x</sub>	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 Units #1, #2, #3 or #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)	$PM_{10}$ $SO_2$ $NO_x$	every year CEM CEM
II. Holman Boiler	$NO_x$	every three years & alternate method according to applicable 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 <sub>x</sub>	9.5 lbs/hr
Combined Heat Plant	NO <sub>x</sub>	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 <sub>x</sub>	every three years*
Combined Heat Plant	NO <sub>x</sub>	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.

iii. Molybdenum Autoclave Project (MAP):

A. Emissions to the atmosphere from the Natural Gas Turbine combined with Duct Burner and with Turbine Electric Generator (TEG) Firing shall not exceed the following rate:

Emission Point	Pollutant	Maximum Emission Rate
Combined Heat Plant	NO <sub>x</sub>	5.01 lbs/hr

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

Emission Point	Pollutant	Testing Frequency
Combined Heat Plant	NO <sub>x</sub>	every year

To determine mass emission rates (lbs/hr, etc.), the pollutant concentration as determined by the appropriate methods above, shall be multiplied by the volumetric flow rate and any necessary conversion factors to give the results in the specified units of the emission limitation.

- C. Standard operating procedures shall be followed during startup and shutdown operations to minimize emissions.

- j. PacifiCorp Energy: Gadsby Power Plant
  - i. Steam Generating Unit #1:
    - A. Emissions of NO<sub>x</sub> shall be no greater than 179 lbs/hr on a three (3) hour block average basis.
    - B. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO<sub>x</sub> and O<sub>2</sub> monitors to determine compliance with the NO<sub>x</sub> limitation. The CEM shall operate as outlined in IX.H.1.f.
  - ii. Steam Generating Unit #2:
    - A. Emissions of NO<sub>x</sub> shall be no greater than 204 lbs/hr on a three (3) hour block average basis.
    - B. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO<sub>x</sub> and O<sub>2</sub> monitors to determine compliance with the NO<sub>x</sub> limitation.
  - iii. Steam Generating Unit #3:
    - A. Emissions of NO<sub>x</sub> 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. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO<sub>x</sub> and O<sub>2</sub> monitors to determine compliance with the NO<sub>x</sub> 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 Turbine Units:
    - A. Total emissions of NO<sub>x</sub> 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. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO<sub>x</sub> and O<sub>2</sub> monitors to determine compliance with the NO<sub>x</sub> 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 valves open and natural gas is supplied to the combustion turbines

- B. Startup ends when either of the following conditions is met:
  - I. The NO<sub>x</sub> water injection pump is operational, the dilution air temperature is greater than 600°F, the stack inlet temperature reaches 570°F, the ammonia block valve 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<sub>10</sub> Cap

By no later than January 1, 2019, combined emissions of PM<sub>10</sub> 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<sub>10</sub>: 1.9 lb/MMscf

Condensable PM<sub>10</sub>: 5.7 lb/MMscf

Plant gas:

Filterable PM<sub>10</sub>: 1.9 lb/MMscf

Condensable PM<sub>10</sub>: 5.7 lb/MMscf

Fuel Oil: The PM<sub>10</sub> emission factor shall be determined from the latest edition of AP-42

Cooling Towers: The PM<sub>10</sub> emission factor shall be determined from the latest edition of AP-42

FCC Wet Scrubber:

The PM<sub>10</sub> 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<sub>10</sub> 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. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the Source-wide PM<sub>10</sub> Cap shall be determined for each day as follows:

Total 24-hour PM<sub>10</sub> emissions for the emission points shall be calculated by adding the daily results of the PM<sub>10</sub> 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<sub>10</sub> 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<sub>x</sub> Cap

By no later than January 1, 2019, combined emissions of NO<sub>x</sub> shall not exceed 1.988 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.ii.B below, the default emission factors to be used are as follows:

Natural gas/refinery fuel gas combustion using:

Low NO<sub>x</sub> burners (LNB): 41 lbs/MMbtu

Ultra-Low NO<sub>x</sub> (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<sub>x</sub> stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr has already been performed and shall be conducted at least once every three (3) years 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 for each combustion type listed in IX.H.2.k.ii.A above. Stack testing shall be performed as outlined in IX.H.1.e.

C. Compliance with the source-wide NO<sub>x</sub> Cap shall be determined for each day as follows:

Total 24-hour NO<sub>x</sub> 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<sub>x</sub> CEM shall be used to calculate daily NO<sub>x</sub> 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<sub>x</sub> 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<sub>2</sub> Cap

By no later than January 1, 2019, combined emissions of SO<sub>2</sub> shall not exceed 3.1 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. The default emission factors to be used are as follows:

Natural gas: EF = 0.60 lb/MMscf

Propane: EF = 0.60 lb/MMscf

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

Plant fuel gas: the emission factor shall be calculated from the H<sub>2</sub>S measurement or from the SO<sub>2</sub> 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<sub>2</sub> Cap shall be determined for each day as follows:

Total daily SO<sub>2</sub> emissions shall be calculated by adding the daily SO<sub>2</sub> emissions for natural gas, plant fuel gas, and propane combustion to those from the wet gas scrubber stack.

Daily SO<sub>2</sub> emissions from the FCCU wet gas scrubber stack shall be determined by multiplying the SO<sub>2</sub> concentration in the flue gas by the flow rate of the flue gas. The SO<sub>2</sub> concentration in the flue gas shall be determined by a CEM as outlined in IX.H.1.f.

Daily SO<sub>2</sub> 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<sub>2</sub>S (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.

1. 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% O2 dry)
A. Boiler #3	NO <sub>x</sub>	187
B. Boilers #4a & #4b	NO <sub>x</sub>	9
C. Boilers #5a & #5b	NO <sub>x</sub>	9
D. Turbine	NO <sub>x</sub>	9
E. Turbine and WHRU Duct burner	NO <sub>x</sub>	15

\*Boiler #4 will be replaced with Boiler #4a and #4b by 2018.

- 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	NO <sub>x</sub>	*	every year#
B. Boilers #4a & 4b	NO <sub>x</sub>	2018	every year#
C. Boilers #5a & 5b	NO <sub>x</sub>	2017	every year#
D. Turbine	NO <sub>x</sub>	*	every year#
E. Turbine and WHRU Duct burner	NO <sub>x</sub>	*	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.

# 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). 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 portable monitor was operated in accordance with manufacturer's specifications. .

- iii. After January 1, 2019, Boiler #3 shall only be used as a back-up/peaking boiler and shall not exceed 300 hours of operation per rolling-12 months. Boiler #3 may be operated on a continuous basis if it is equipped with low NO<sub>x</sub> burners or is replaced with a boiler that has low NO<sub>x</sub> burners.

- m. West Valley Power Holdings, LLC.: West Valley Power Plant.
  - i. Total emissions of NO<sub>x</sub> from all five (5) turbines combined shall be no greater than 1050 lb of NO<sub>x</sub> 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. Total emissions of NO<sub>x</sub> from all five (5) turbines shall include the sum of all periods in the day including periods of startup, shutdown, and maintenance.
  - iii. The NO<sub>x</sub> emission rate (lb/hr) shall be determined by CEM. The CEM shall operate as outlined in IX.H.1.f.

### H.3 Source Specific Emission Limitations in Utah County PM<sub>10</sub> Nonattainment/Maintenance Area

- a. Brigham Young University: Main Campus
- i All central heating plant units shall operate on natural gas from November 1 to February 28 each season beginning in the winter season of 2013-2014. Fuel oil may be used as backup fuel during periods of natural gas curtailment. The sulfur content of the fuel oil shall not exceed 0.0015 % by weight. BYU must maintain a fuel specification certification document from the fuel supplier with the sulfur content guarantee. Alternatively, sulfur content may be verified through testing completed by BYU or the fuel supplier using ASTM Method D-4294-10 or EPA approved equivalent acceptable to the Director.
  - ii. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

Emission Point	Pollutant	ppm (7% O <sub>2</sub> dry)*		lb/hr	
A. Unit #1	NO <sub>x</sub>	95	36	9.55	5.44
B. Unit #4	NO <sub>x</sub>	127	36	38.5	19.2
C. Unit #6	NO <sub>x</sub>	127	36	38.5	19.2

\* Unit #1 NO<sub>x</sub> limit is 95 ppm (9.55 lb/hr) until it operates for more than 300 hours during a rolling 12-month period, then the limit will be 36 ppm (5.44 lb/hr). The NO<sub>x</sub> limit for units #4 and #6 is 127 ppm (38.5 lb/hr) and starting on December 31, 2018, the limit will then be 36 ppm (19.2 lb/hr).

Emission Point	Pollutant	ppm (7% O <sub>2</sub> dry)		lb/hr
D. Unit #2	NO <sub>x</sub>	331		37.4
	SO <sub>2</sub>	597		56.0
E. Unit #3	NO <sub>x</sub>	331		37.4
	SO <sub>2</sub>	597		56.0
F. Unit #5	NO <sub>x</sub>	331		74.8
	SO <sub>2</sub>	597		112.07

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

Emission Point	Pollutant	Initial test	Test Frequency
A. Unit #1	NO <sub>x</sub>	&	every year*
B. Unit #2	NO <sub>x</sub>	#	every year*
C. Unit #3	NO <sub>x</sub>	#	every year*
D. Unit #4	NO <sub>x</sub>	#	every year*
E. Unit #5	NO <sub>x</sub>	#	every year*
F. Unit #6	NO <sub>x</sub>	#	every year*

Stack tests shall be performed in accordance with IX.H.1.e.

- & If Unit #1 is operated for more than 100 hours per rolling 12-month period, the stack test shall be performed within 60 days of exceeding 100 hours of operations. Unit #1 shall only be operated as a back-up boiler to Units #4 and #6 and shall not be operated more than 300 hours per rolling 12-month period. If Unit #1 operates more than 300 hours per rolling 12-month period, then low NO<sub>x</sub> burners with Flue Gas Recirculation shall be installed and tested within 18 months of exceeding 300 hours of operation and the maximum NO<sub>x</sub> concentration shall be 36 ppm.
- # The test shall be performed at least every 3 years based on the date of the last stack test. Units #4 and #6 shall be retested by March 1, 2018.
- \* 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). 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 portable monitor was operated in accordance with manufacturer's specifications.

iv. Central Heating Plant Coal-Fired Boilers

- A. Startup and shutdown events shall not exceed 216 hours per boiler per 12-month rolling period.
- B. The sulfur content of any coal or any mixture of coals burned shall not exceed either of the following:
  - I. 0.54 pounds of sulfur per million BTU heat input as determined by ASTM Method D-4239-85, or EPA-approved equivalent acceptable to the Director.
  - II. 0.60% by weight as determined by ASTM Method D-4239-85, or EPA-approved equivalent acceptable to the Director.

For the sulfur content of coal, Brigham Young University shall either:

- III. Determine the weight percent sulfur and the fuel heating value by submitting a coal sample to a laboratory, acceptable to the Director, on no less than a monthly basis; or
- IV. For each delivery of coal, inspect the fuel sulfur content expressed as weight % determined by the vendor using methods of the ASTM; or

- V. For each delivery of coal, inspect documentation provided by the vendor that indirectly demonstrates compliance with this provision.

b. Geneva Nitrogen Inc.: Geneva Nitrogen Plant

i. Prill Tower:

PM<sub>10</sub> emissions (filterable and condensable) shall not exceed 0.236 ton/day

PM<sub>2.5</sub> emissions (filterable and condensable) shall not exceed 0.196 ton/day

A day is defined as from midnight to the following midnight.

ii. Testing

A. Stack testing shall be performed as specified below:

I. Frequency: Emissions shall be tested every three years. The test shall be performed as soon as possible and in no case later than December 31, 2017.

B. The daily limit shall be calculated by multiplying the most recent stack test results by the appropriate hours of operation for each day.

iii. Montecatini Plant:

NO<sub>x</sub> emissions shall not exceed 30.8 lb/hr

iv. Weatherly Plant:

NO<sub>x</sub> emissions shall not exceed 18.4 lb/hr

v. Testing

A. Stack testing for NO<sub>x</sub> shall be performed as specified below:

I. Stack testing to show compliance with the NO<sub>x</sub> emission limitations shall be performed as specified below:

1. Testing and Frequency. Emissions shall be tested every three years using an EPA approved test method.

II. NO<sub>x</sub> concentration (ppmdv) shall be used as an indicator to provide a reasonable assurance of compliance with the NO<sub>x</sub> emission limitation as specified below:

1. Measurement Approach: NO<sub>x</sub> concentration (ppmdv) shall be determined by using a continuous NO<sub>x</sub> monitoring system.

2. Performance Criteria:

i. QA/QC Practices and Criteria: The continuous monitoring system shall be operated, calibrated, and maintained in accordance with manufacture's recommendations. Zero and span drift tests shall be conducted on a daily

basis.

III. The EPA approved method test for the Montecatini Plant shall be performed as soon as possible and in no case later than December 31, 2017, and the test for the Weatherly Plant shall be performed as soon as possible and in no case later than December 31, 2018.

vi. Start-up/Shut-down

A. Startup / Shutdown Limitations:

- I. Planned shut-down and start-up events shall not exceed 50 hours per acid plant (Montecatini or Weatherly) per 12-month rolling period.
- II. Total startup and shutdown events shall not exceed four hours per acid plant in any one calendar day.

c. PacifiCorp Energy: Lake Side Power Plant

i. Block #1 Turbine/HRSG Stacks:

A. Emissions of NO<sub>x</sub> shall not exceed 14.9 lb/hr on a 3-hr average basis

B. Compliance with the above conditions shall be demonstrated as follows:

I. NO<sub>x</sub> monitoring shall be through use of a CEM as outlined in IX.H.1.f

ii. Block #2 Turbine/HRSG Stacks:

A. Emissions of NO<sub>x</sub> shall not exceed 18.1 lb/hr on a 3-hr average basis

B. Compliance with the above conditions shall be demonstrated as follows:

I. NO<sub>x</sub> monitoring shall be through use of a CEM as outlined in IX.H.1.f

iii. Startup / Shutdown Limitations:

A. Block #1:

I. Startup and shutdown events shall not exceed 613.5 hours per turbine per 12-month rolling period.

II. Total startup and shutdown events shall not exceed 14 hours per turbine in any one calendar day.

III. Cumulative short-term transient load excursions shall not exceed 160 hours per 12-month rolling period.

IV. During periods of transient load conditions, NO<sub>x</sub> emissions from the Block #1 Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O<sub>2</sub>.

B. Block #2:

I. Startup and shutdown events shall not exceed 553.6 hours per turbine per 12-month rolling period.

II. Total startup and shutdown events shall not exceed 8 hours per turbine in any one calendar day.

III. Cumulative short-term transient load excursions shall not exceed 160 hours per 12-month rolling period.

IV. During periods of transient load conditions, NO<sub>x</sub> emissions from the Block #2 Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O<sub>2</sub>.

C. Definitions:

- I. Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr emission limits listed in IX.H.3.c.i and ii above.
- II. Shutdown is defined as the period beginning with the initiation of turbine shutdown sequence and ending with the cessation of firing of the gas turbine engine.
- III. Transient load conditions are those periods, not to exceed four consecutive 15-minute periods, when the 15-minute average NO<sub>x</sub> concentration exceeds 2.0 ppmv dry @ 15% O<sub>2</sub>. Transient load conditions consist of the following:
  1. Initiation/shutdown of combustion turbine inlet air-cooling.
  2. Rapid combustion turbine load changes.
  3. Initiation/shutdown of HRSG duct burners.
  4. Provision of Ancillary Services and Automatic Generation Control.
- IV. For purposes of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

e. Payson City Corporation: Payson City Power

- i. Emissions of NO<sub>x</sub> shall be no greater than 1.54 ton per day for all engines combined.
- 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:

$$\text{Emissions (tons/day)} = (\text{Power production in kW-hrs/day}) \times (\text{Emission factor in grams/kW-hr}) \times (1 \text{ lb}/453.59 \text{ g}) \times (1 \text{ ton}/2000 \text{ lbs})$$

- A. The NO<sub>x</sub> emission factor for each engine shall be derived from the most recent stack test. 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.
- B. NO<sub>x</sub> emissions shall be calculated on a daily basis.
- C. A day is equivalent to the time period from midnight to the following midnight.
- D. The number of kilowatt hours generated by each engine shall be recorded on a daily basis with an electrical meter.

f. Provo City Power: Power Plant

- i. NO<sub>x</sub> emissions from the operation of all engines at the plant shall not exceed 2.45 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:

$$\text{Emissions (tons/day)} = (\text{Power production in kW-hrs/day}) \times (\text{Emission factor in grams/kW-hr}) \times (1 \text{ lb}/453.59 \text{ g}) \times (1 \text{ ton}/2000 \text{ lbs})$$

- A. The NO<sub>x</sub> emission factor for each engine shall be derived from the most recent stack test. Stack tests shall be performed in accordance with IX.H.1.e. Each engine shall be tested every 8,760 hours of operation or at least every three years from the previous test, whichever occurs first.
- B. NO<sub>x</sub> emissions shall be calculated on a daily basis.
- C. A day is equivalent to the time period from midnight to the following midnight.
- D. The number of kilowatt hours generated by each engine shall be recorded on a daily basis with an electrical meter.

g. Springville City Corporation: Whitehead Power Plant

- i. NO<sub>x</sub> emissions from the operation of all engines at the plant shall not exceed 1.68 tons per day.
- ii. Internal combustion engine emissions shall be calculated from the operating data recorded by the CEM. CEM will be performed in accordance with IX.H.1.f. A day is equivalent to the time period from midnight to the following midnight. Emissions shall be calculated for NO<sub>x</sub> for each individual engine by the following equation:

$$D = (X * K)/453.6$$

Where:

X = grams/kW-hr rate for each generator (recorded by CEM)

K = total kW-hr generated by the generator each day (recorded by output meter)

D = daily output of pollutant in lbs/day

## 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<sub>10</sub> State Implementation Plan and this PM<sub>10</sub> 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<sub>10</sub> 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<sub>10</sub> nonattainment/maintenance area shall, for the purpose of this PM<sub>10</sub> Maintenance Plan:
    - A. Achieve an emission rate equivalent to no more than 9.8 kg of SO<sub>2</sub> per 1,000 kg of coke burn- off from any Catalytic Cracking unit by use of low-SO<sub>x</sub> 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<sub>10</sub>, SO<sub>2</sub>, and NO<sub>x</sub> 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<sub>x</sub> and PM<sub>10</sub> emission factors shall be determined from AP-42 or from test data.

For SO<sub>x</sub>, 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<sub>2</sub>S 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:

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

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<sub>10</sub> Emissions

- A. Combined emissions of filterable PM<sub>10</sub> 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<sub>10</sub> contribution from the Catalyst Regeneration System shall be calculated using the following equation:

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

wherein the emission factor (22 lbs/kbbl) may be re-established by stack testing. Total 24-hour PM<sub>10</sub> 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<sub>2</sub> 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<sub>2</sub> emission from the Catalyst Regeneration System shall be calculated using the following equation:

$$\text{SO}_2 = [43.3 \text{ lb SO}_2/\text{hr} / 7,688 \text{ bbl feed/day}] \times [(\text{operational feed rate in bbl/day}) \times (\text{wt\% sulfur in feed} / 0.1878 \text{ wt\%}) \times (\text{operating hr/day})]$$

The FCC feed weight percent sulfur concentration shall be determined by the refinery laboratory every 30 days with one or more analyses. Alternatively, SO<sub>2</sub> 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<sub>2</sub> 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<sub>x</sub> Emissions

A. Combined emissions of NO<sub>x</sub> 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<sub>x</sub> emission from the Catalyst Regeneration System shall be calculated using the following equation:

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

wherein the scalar value (180 ppm) may be re-established by stack testing.

Alternatively, NO<sub>x</sub> 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<sub>x</sub> 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<sub>10</sub> Emissions

- A. Combined emissions of filterable PM<sub>10</sub> 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<sub>2</sub> 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<sub>2</sub> 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<sub>x</sub> Emissions

- A. Combined emissions of NO<sub>x</sub> 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<sub>x</sub> 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<sub>10</sub> Emissions

- A. Combined emissions of filterable PM<sub>10</sub> 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<sub>2</sub> Emissions

- A. Combined emissions of SO<sub>2</sub> 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 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 FCC wet scrubbers shall be determined using a Continuous Emissions Monitor (CEM) in accordance with IX.H.1.f.

iii. NO<sub>x</sub> Emissions:

- A. Combined emissions of NO<sub>x</sub> 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<sub>10</sub> Emissions

- A. Combined emissions of filterable PM<sub>10</sub> 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<sub>2</sub> Emissions

- A. Combined emissions of SO<sub>2</sub> 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<sub>2</sub> concentration in the flue gas by the mass flow of the flue gas.

The SO<sub>2</sub> concentration in the flue gas shall be determined by a continuous emission monitor (CEM).

iii. NO<sub>x</sub> Emissions

- A. Combined emissions of NO<sub>x</sub> 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<sub>2.5</sub>**

- 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 (either PM<sub>10</sub> and/or PM<sub>2.5</sub> listed in Subsections IX.H.12 and IX.H.13 include both filterable 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<sub>2</sub> Removal & PM, SO<sub>2</sub>, NO<sub>x</sub> 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.  $PM_{2.5}$ : 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.
  - F.  $SO_2$ : 40 CFR 60 Appendix A, Method 6C, or other EPA-approved testing methods acceptable to the Director.
  - G.  $NO_x$ : 40 CFR 60 Appendix A, Method 7E, or other EPA-approved testing methods acceptable to the Director.
  - H. VOC: 40 CFR 60 Appendix A, Method 25A or other EPA-approved testing methods acceptable to the Director.
  - I. 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.
  - J. 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.
  - K. 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<sub>2</sub> Emissions

I. By no later than January 1, 2018, each owner or operator of an FCCU shall comply with an SO<sub>2</sub> 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. By no later than January 1, 2018, each owner or operator of an FCCU shall comply with an emission limit of 1.0 pounds PM per 1000 pounds coke burned on a 3-hour average basis.

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 years at each FCCU.

III. By 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<sub>2.5</sub> emissions as appropriate

ii. Limits on Refinery Fuel Gas

A. By no later than January 1, 2018, all petroleum refineries in or affecting the PM<sub>2.5</sub> nonattainment area shall reduce the H<sub>2</sub>S content of the refinery plant gas to 60 ppm or less as described in 40 CFR 60.102a. Compliance shall be based on a rolling average of 365 days. The owner/operator shall comply with the fuel gas monitoring requirements of 40 CFR 60.107a and the related recordkeeping and reporting requirements of 40 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. 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 as soon as practicable but no later than January 1, 2015. 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 but no later than January 1, 2016.
    - 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. Beginning January 1, 2018, all hydrocarbon flares at petroleum refineries located in or affecting a designated PM<sub>2.5</sub> non-attainment 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. By no later than January 1, 2019, all major source petroleum refineries in or affecting a designated PM<sub>2.5</sub> non-attainment area within the State 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 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<sub>2.5</sub> 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 PM<sub>2.5</sub> levels exceed 35 ug/m<sup>3</sup> 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) will be limited to 50 percent of the treatment facility's Department of Solid and Hazardous Waste permitted daily limit. During this period, on days when open burning occurs, records will be maintained identifying the quantity burned and the PM<sub>2.5</sub> level at the nearest real-time monitoring station.
  - ii. During the period November 1 to February 28/29, on days when the 24-hour average PM<sub>2.5</sub> levels exceed 35 ug/m<sup>3</sup> 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 PM<sub>2.5</sub> level exceeds 35 ug/m<sup>3</sup> 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 PM<sub>2.5</sub> level has returned to a concentration below 35 ug/m<sup>3</sup> 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 PM<sub>2.5</sub> 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 NO<sub>x</sub> 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 NO<sub>x</sub> 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.

b. Big West Oil Refinery

i. Source-wide PM<sub>2.5</sub>:

Following installation of the Flue Gas Blow Back Filter (FGF), but no later than January 1, 2019, combined emissions of PM<sub>2.5</sub> (filterable+condensable) shall not exceed 0.29 tons per day and 72.5 tons per rolling 12-month period. By no later than January 1, 2019, Big West Oil shall conduct stack testing to establish the ratio of condensable PM<sub>2.5</sub> 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<sub>2.5</sub>: 1.9 lb/MMscf

Condensable PM<sub>2.5</sub>: 5.7 lb/MMscf

Plant gas:

Filterable PM<sub>2.5</sub>: 1.9 lb/MMscf

Condensable PM<sub>2.5</sub>: 5.7 lb/MMscf

Fuel Oil: The PM<sub>2.5</sub> emission factors shall be determined from the latest edition of AP-42

FCC Stacks: The PM<sub>2.5</sub> 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<sub>2.5</sub> stack testing on the FCC shall be performed initially no later than January 1, 2019 and at least once every three (3) years thereafter. Stack testing shall be performed as outlined in IX.H.11.e.

C. Compliance with the source-wide PM<sub>2.5</sub> Cap shall be determined for each day as follows:

Total 24-hour PM<sub>2.5</sub> emissions for the emission points shall be calculated by adding the daily results of the PM<sub>2.5</sub> 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<sub>2.5</sub> 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:

$$\text{Emissions} = \text{Emission Factor (lb/MMscf)} * \text{Gas Consumption (MMscf/24 hrs)} / (2,000 \text{ lb/ton})$$

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

The daily PM<sub>2.5</sub> emissions from the FCC shall be calculated using the following equation:

$$E = FR * EF$$

Where:

E = Emitted PM<sub>2.5</sub>

FR = Feed Rate to Unit (kbbbl/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<sub>x</sub> Cap

By no later than January 1, 2019, combined emissions of NO<sub>x</sub> 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<sub>x</sub> stack testing on natural gas/refinery fuel gas combustion equipment above 40 MMBtu/hr has been performed and the next stack test shall be performed within 3 years of the previous stack test. At that time a new flow-weighted average emission factor in terms of: lbs/MMBtu shall be derived for each combustion type listed in IX.H.12.b.ii.A above. Stack testing shall be performed as outlined in IX.H.11.e.

C. Compliance with the source-wide NO<sub>x</sub> Cap shall be determined for each day as follows:

Total 24-hour NO<sub>x</sub> 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:

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

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<sub>x</sub> emissions from the FCC shall be calculated using a CEM as outlined in IX.H.11.f

Total daily NO<sub>x</sub> emissions shall be calculated by adding the results of the above NO<sub>x</sub> 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<sub>2</sub> Cap

By no later than January 1, 2019, combined emissions of 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<sub>2</sub>/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:

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

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<sub>2</sub> Cap shall be determined for each day as follows:

Total daily SO<sub>2</sub> emissions shall be calculated by adding the daily SO<sub>2</sub> emissions for natural gas and plant fuel gas combustion, to those from the FCC and SRU stacks.

The daily SO<sub>x</sub> 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<sub>2</sub>S (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<sub>2</sub> 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.

c. 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:  
NO<sub>x</sub> 0.6 g/kW-hr
  - B. GT #2 and GT #3 (each TITAN Turbine) Catalytic-controlled Exhaust Stack:  
NO<sub>x</sub> 15 ppm
- ii. Compliance to the above emission limitations shall be determined by stack test as outlined in Section IX Part H.11.e of this SIP.
  - 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.

d. Central Valley Water Reclamation Facility: Wastewater Treatment Plant

- i. NO<sub>x</sub> 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:

$$\text{Emissions (tons/day)} = (\text{Power production in kW-hrs/day}) \times (\text{Emission factor in grams/kW-hr}) \times (1 \text{ lb}/453.59 \text{ g}) \times (1 \text{ ton}/2000 \text{ lbs})$$

- A. Stack tests shall be performed in accordance with IX.H.11.e. Each engine shall be tested at least every three years from the previous test.
- B. The NO<sub>x</sub> emission factor for each engine shall be derived from the most recent stack test.
- C. NO<sub>x</sub> 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.

e. 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 for reduction of NO<sub>x</sub> emission.
  - a. Effective January 1, 2019, or upon source start-up, whichever comes later, NO<sub>x</sub> emissions shall not exceed 56 lb/hr.
  - 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 for reduction of PM emissions.
  - 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.
  - b. Effective January 1, 2019, or upon source start-up, whichever comes later, PM<sub>2.5</sub> emissions shall not exceed 1.5 lbs/ton of stone feed.
  - 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)
- 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<sub>x</sub> 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.

f. Chevron Products Company - Salt Lake Refinery

i. Source-wide PM<sub>2.5</sub> Cap

By no later than January 1, 2019, combined emissions of PM<sub>2.5</sub> (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<sub>2.5</sub>: 1.9 lb/MMscf

Condensable PM<sub>2.5</sub>: 5.7 lb/MMscf

Plant gas:

Filterable PM<sub>2.5</sub>: 1.9 lb/MMscf

Condensable PM<sub>2.5</sub>: 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<sub>2.5</sub> 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<sub>2.5</sub> 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. Stack testing shall be performed as outlined in IX.H.11.e.

C. Compliance with the source-wide PM<sub>2.5</sub> Cap shall be determined for each day as follows:

Total 24-hour PM<sub>2.5</sub> emissions for the emission points shall be calculated by adding the daily results of the PM<sub>2.5</sub> 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<sub>2.5</sub> 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<sub>x</sub> Cap

By no later than January 1, 2019, combined emissions of NO<sub>x</sub> 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<sub>x</sub> stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr has been performed and shall be conducted at least once every three (3)

years from the date of the last stack test. At that time a new flow-weighted average emission factor in terms of: lbs/MMbtu shall be derived for each combustion type listed 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<sub>x</sub> Cap shall be determined for each day as follows:

Total 24-hour NO<sub>x</sub> 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<sub>x</sub> CEM shall be used to calculate daily NO<sub>x</sub> 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<sub>x</sub> 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<sub>2</sub>

By no later than January 1, 2019, combined emissions of SO<sub>2</sub> 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<sub>2</sub> 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:

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

Plant gas: the emission factor shall be calculated from the H<sub>2</sub>S measurement obtained from the H<sub>2</sub>S 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<sub>2</sub> Cap shall be determined for each day as follows:

Total daily SO<sub>2</sub> emissions shall be calculated by adding the daily SO<sub>2</sub> 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<sub>2</sub>S (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<sub>x</sub> from each rich-burn compressor engine shall not exceed the following:

Engine Number	NO <sub>x</sub> in ppmvd @ 0% O <sub>2</sub>
1	236
2	208
3	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. 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

g. Compass Minerals Ogden Inc.

- i. NO<sub>x</sub> emissions to the atmosphere from the indicated emission point shall not exceed the following concentrations:

Emission Points	Concentration (ppm)
Boiler #1	9.0
Boiler #2	9.0

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 subsequent to the initial compliance test.

- ii. PM<sub>2.5</sub> emissions to the atmosphere from each of the following emission points shall not exceed a concentration of 0.01 grains/dscf (@ 68 degrees F and 29.92 in Hg):

- Source
- SOP Plant Compaction/Loadout
- Salt Plant Screening
- SOP Plant Dryer D-001
- SOP Plant Dryer D-002
- SOP Plant Dryer D-003
- SOP Plant Dryer D-004
- SOP Plant Drying Circuit Fluid Bed Heater D-005
- Salt Plant Dryer D-501

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.

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

- iii. PM<sub>2.5</sub> emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

Source	Concentration (grains/dscf) (@ 68 degrees F 29.92 in Hg)
SOP Loadout	0.01
SOP Silo Dust Collection	0.01
SOP Plant Compaction	0.020
Salt Plant Dust Collection	0.01

Bulk Truck Salt Loadout	0.0053
Mag Chloride Plant	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.

iv. Dryer Requirements

- A. By October 1, 2017, dryer units D-002 and D-004 shall be retired and removed from service
- B. By January 1, 2017, emissions of NO<sub>x</sub> from all other dryers with heat input in excess of 5 MMBtu/hour shall not exceed 20 ppmvd at 3% O<sub>2</sub>
- C. Compliance to the above NO<sub>x</sub> 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.

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

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

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

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

Residence times shall be determined by

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

Where

R = residence time

V = interior volume of the incinerator – ft<sup>3</sup>

Q<sub>max</sub> = maximum exhaust gas flow rate – ft<sup>3</sup>/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  $\pm 25^{\circ}\text{F}$  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.

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

i. Source-wide PM<sub>2.5</sub> Cap

By no later than January 1, 2019, PM<sub>2.5</sub> 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<sub>2.5</sub>/MMscf

NSPS combustion equipment: 0.52 lb PM<sub>2.5</sub>/MMscf

Fuel oil:

The filterable PM<sub>2.5</sub> emission factor for fuel oil combustion shall be determined based on the sulfur content of the oil as follows:

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

The condensable PM<sub>2.5</sub> emission factor for fuel oil combustion shall be determined from the latest edition of AP-42.

FCC Wet Scrubbers:

The PM<sub>2.5</sub> 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

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 thereafter. At that time a new flow-weighted average emission factor in terms of: lb PM<sub>2.5</sub>/MMBtu shall be derived. Stack testing shall be performed as outlined in IX.H.11.e.

C. Compliance with the source-wide PM<sub>2.5</sub> Cap shall be determined for each day as follows:

Total 24-hour PM<sub>2.5</sub> emissions for the emission points shall be calculated by adding the daily results of the PM<sub>2.5</sub> 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<sub>2.5</sub> 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:

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Natural/Plant Gas Consumption (MMscf/day)} / (2,000 \text{ lb/ton})$$
$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/kgal)} * \text{Fuel Oil Consumption (kgal/day)} / (2,000 \text{ lb/ton})$$

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<sub>x</sub> Cap

By no later than January 1, 2019, NO<sub>x</sub> 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<sub>x</sub> burners (LNB): 41 lbs/MMscf

Ultra-Low NO<sub>x</sub> (ULNB) burners: 0.04 lbs/MMbtu

Next Generation Ultra Low NO<sub>x</sub> 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<sub>x</sub> Cap shall be determined for each day as follows:

Total daily NO<sub>x</sub> emissions for emission points shall be calculated by adding the results of the NO<sub>x</sub> 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:

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

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

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMBTU)} * \text{Burner Heat Rating (BTU/hr)} * 24 \text{ hours per day} / (2,000 \text{ lb/ton})$$

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

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<sub>2</sub> Cap

By no later than January 1, 2019, the emission of SO<sub>2</sub> 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<sub>2</sub>/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<sub>2</sub>S 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:

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

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<sub>2</sub> Cap shall be determined for each day as follows:

Total daily SO<sub>2</sub> emissions shall be calculated by adding daily results of the SO<sub>2</sub> 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:

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

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

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

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<sub>2</sub>S (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.

j. 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. 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.

k. Kennecott Utah Copper: Power Plant

i. UTAH POWER PLANT

- A. Boilers #1, #2, and #3 shall not be operated after January 1, 2018, or upon commencing operations of Unit #5 (combined-cycle, natural gas-fired combustion turbine), whichever is sooner.
- B. Unit #5 (combined cycle, natural gas-fired combustion turbine) shall not exceed the following emission rates to the atmosphere:

POLLUTANT	lb/hr	lb/event	ppmdv (15% O <sub>2</sub> dry)
I. PM <sub>2.5</sub> with duct firing: Filterable + condensable	18.8		
II. VOC:			2.0*
III. NO <sub>x</sub> : Startup / Shutdown		395	2.0*

\* 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 NO<sub>x</sub> 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.12.k.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 <sub>2.5</sub>	every year
II.	NO <sub>x</sub>	every year
III.	VOC	every year

D. Prior to January 1, 2018, the following requirements are applicable to Units #1, #2, #3, and #4 during the period November 1 to February 28/29 inclusive:

I. 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 68°F, 29.92 in. Hg	ppmdv (3% O <sub>2</sub> )
1. PM <sub>2.5</sub> Units #1, #2, #3 and #4		
filterable	0.004	
filterable + condensable	0.03	
2. NO <sub>x</sub> Units #1, #2 and #3		336
3. NO <sub>x</sub> : Unit #4 (Unit #4 after January 1, 2018)		336 60

III. When using coal 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 <sub>2</sub> ) 68°F, 29.92 in. Hg
1. PM <sub>2.5</sub> Filterable	0.029	
filterable + condensable	0.29	
2. NO <sub>x</sub> : Units #1, #2 and #3		426.5
Unit #4		384

IV. If the units are operated during the months specified above, stack testing to show compliance with the emission limitations in H.12.k.i.D.II and III shall be performed as follows for the following air contaminants:

Pollutant	Test Frequency	Initial Test
1. PM <sub>2.5</sub>	every year	#
2. NO <sub>x</sub>	every year	#

# Initial compliance testing is required for Unit #4 after low NO<sub>x</sub> burner installation. 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 heat input during all compliance testing shall be no less than 90% of the design rate.

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

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

E. The following requirements are applicable to Units #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	ppmdv (3% O <sub>2</sub> ) 68°F, 29.92 in Hg
1. Units #1, #2, #3, #4		
(i) PM <sub>2.5</sub> filterable	0.029	
(ii) filterable + condensable	0.29	
(iii) NO <sub>x</sub> Units #1, #2, #3		426.5
(iv) NO <sub>x</sub> Unit #4		384

II. If the units are operated during the months specified above, stack testing to show compliance with the emission limitations in H.12.k.i.E.I shall be performed as follows for the following air contaminants:

Pollutant	Test Frequency
1. PM <sub>2.5</sub>	every year
2. NO <sub>x</sub>	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 Units #1, #2, #3 or #4.

1. 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<sub>2.5</sub>
  - a. 85 lbs/hr (filterable)
  - b. 434 lbs/hr (filterable + condensable)
2. SO<sub>2</sub>
  - a. 552 lbs/hr (3 hr. rolling average)
  - b. 422 lbs/hr (daily average)
3. NO<sub>x</sub> 154 lbs/hr (daily average)

II. Holman Boiler

1. NO<sub>x</sub>
  - 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 <sub>2.5</sub>	Every Year
	SO <sub>2</sub>	CEM
	NO <sub>x</sub>	CEM
II. Holman Boiler	NO <sub>x</sub>	Every three years and 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 an alternate method according to applicable NSPS standards.

C. During startup/shutdown operations, NO<sub>x</sub> and SO<sub>2</sub> 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 <sub>x</sub>	9.5 lbs/hr
Combined Heat Plant	NO <sub>x</sub>	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 <sub>x</sub>	every three years*
Combined Heat Plant	NO <sub>x</sub>	every year

Stack testing shall be performed on boilers that have operated more than 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. Records shall be kept on site which indicate the date, and time of startups and shutdowns.

iii. Molybdenum Autoclave Project (MAP):

- A. Emissions to the atmosphere from the Natural Gas Turbine shall not exceed the following rate:

EMISSION POINT	POLLUTANT	MAXIMUM EMISSION RATE
Combined Heat Plant	NO <sub>x</sub>	5.01 lbs/hr

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

EMISSION POINT	POLLUTANT	TESTING FREQUENCY
Combined Heat Plant	NO <sub>x</sub>	every year

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

m. 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<sub>2.5</sub>

1. 17.4 lbs/hr (24 hr. average filterable only)
2. 29.53 lbs/hr (condensable only)

II. SO<sub>2</sub>

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

III. NO<sub>x</sub> 59.5 lbs/hr (calendar-day average)

IV. VOC 22.20 lbs/hr

B. Reheat Furnace #1

NO<sub>x</sub> 15.0 lb/hr

C. Reheat Furnace #2

NO<sub>x</sub> 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 <sub>2.5</sub>	every year
	SO <sub>2</sub>	CEM
	NO <sub>x</sub>	CEM
	VOC	every year
B. Reheat Furnace #1	NO <sub>x</sub>	every year
C. Reheat Furnace #2	NO <sub>x</sub>	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<sub>2</sub> and NO<sub>x</sub> of Condition (i)(A) above, Nucor shall calibrate, maintain and operate the measurement systems for continuously monitoring for SO<sub>2</sub> and NO<sub>x</sub> 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<sub>2.5</sub> 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<sub>2.5</sub> limit, that will constitute compliance with the PM<sub>2.5</sub> limit. If TSP emissions are not below the PM<sub>2.5</sub> limit, the owner/operator shall retest using EPA approved methods specified for PM<sub>2.5</sub> testing, within 120 days.
- C. Startup/shutdown NO<sub>x</sub> and SO<sub>2</sub> emissions are monitored by CEMS.

- n. Olympia Sales Company: Cabinet Manufacturing Facility
  - i. By July 31, 2018, a baghouse control device shall be in operation for control of the process exhaust streams from the Mill, Door, and Sanding areas.
  - ii. Process emissions from the Mill, Door, and Sanding areas shall be exhausted through the baghouse during startup, shutdown, and operations of the plant.
  - iii. The baghouse shall operate a maximum of 4,160 hours per rolling 12-month period. Records of baghouse operation shall be kept for all periods of plant operation. The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining of an operations log.
  - iv. The owner/operator shall comply with all applicable provisions of R307-349.

- o. PacifiCorp Energy: Gadsby Power Plant
  - i. Steam Generating Unit #1:
    - A. Emissions of NO<sub>x</sub> shall be no greater than 179 lbs/hr on a three (3) hour block average basis.
    - B. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO<sub>x</sub> and O<sub>2</sub> monitors to determine compliance with the NO<sub>x</sub> limitation. The CEM shall operate as outlined in IX.H.11.f.
  - ii. Steam Generating Unit #2:
    - A. Emissions of NO<sub>x</sub> shall be no greater than 204 lbs/hr on a three (3) hour block average basis.
    - B. The owner/operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO<sub>x</sub> and O<sub>2</sub> monitors to determine compliance with the NO<sub>x</sub> limitation.
  - iii. Steam Generating Unit #3:
    - A. Emissions of NO<sub>x</sub> 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. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO<sub>x</sub> and O<sub>2</sub> monitors to determine compliance with the NO<sub>x</sub> 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<sub>x</sub> 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. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO<sub>x</sub> and O<sub>2</sub> monitors to determine compliance with the NO<sub>x</sub> 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 valves open and natural gas is supplied to the combustion turbines
  - B. Startup ends when either of the following conditions is met:
    - I. The NO<sub>x</sub> water injection pump is operational, the dilution air temperature is greater than 600°F, the stack inlet temperature reaches 570°F, the ammonia block valve 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.

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

i. Source-wide PM<sub>2.5</sub> Cap

By no later than January 1, 2019, combined emissions of PM<sub>2.5</sub> (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<sub>2.5</sub>: 1.9 lb/MMscf

Condensable PM<sub>2.5</sub>: 5.7 lb/MMscf

Plant gas:

Filterable PM<sub>2.5</sub>: 1.9 lb/MMscf

Condensable PM<sub>2.5</sub>: 5.7 lb/MMscf

Fuel Oil: The PM<sub>2.5</sub> emission factor shall be determined from the latest edition of AP-42

FCC Wet Scrubber:

The PM<sub>2.5</sub> 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.p.i.A above apply until such time as stack testing is conducted as outlined below:

Initial PM<sub>2.5</sub> 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. Stack testing shall be performed as outlined in IX.H.11.e.

C. Compliance with the Source-wide PM<sub>2.5</sub> Cap shall be determined for each day as follows:

Total 24-hour PM<sub>2.5</sub> emissions for the emission points shall be calculated by adding the daily results of the PM<sub>2.5</sub> 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<sub>2.5</sub> 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<sub>x</sub> Cap

By no later than January 1, 2019, combined emissions of NO<sub>x</sub> 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.p.ii.B below, the default emission factors to be used are as follows:

Natural gas/refinery fuel gas combustion using:

Low NO<sub>x</sub> burners (LNB): 0.051 lbs/MMbtu

Ultra-Low NO<sub>x</sub> (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.p.ii.A above apply unless stack testing results are available or emissions are measured by operation of a NO<sub>x</sub> CEMS.

Initial NO<sub>x</sub> stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr has already been performed and shall be conducted at least once every three (3) years 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 for each combustion type listed in IX.H.12.p.ii.A above. 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<sub>x</sub> CEMS.

C. Compliance with the source-wide NO<sub>x</sub> Cap shall be determined for each day as follows:

Total 24-hour NO<sub>x</sub> 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<sub>x</sub> CEM shall be used to calculate daily NO<sub>x</sub> 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<sub>x</sub> 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<sub>2</sub> Cap

By no later than January 1, 2019, combined emissions of SO<sub>2</sub> 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 = 0.60 lb/MMscf

Propane: EF = 0.60 lb/MMscf

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

Plant fuel gas: the emission factor shall be calculated from the H<sub>2</sub>S measurement or from the SO<sub>2</sub> 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<sub>2</sub> Cap shall be determined for each day as follows:

Total daily SO<sub>2</sub> emissions shall be calculated by adding the daily SO<sub>2</sub> emissions for natural gas, plant fuel gas, and propane combustion to those from the wet gas scrubber

stack.

Daily SO<sub>2</sub> emissions from the FCCU wet gas scrubber stack shall be determined by multiplying the SO<sub>2</sub> concentration in the flue gas by the flow rate of the flue gas. The SO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub>S (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, By no later than January 1, 2018, reduce the H<sub>2</sub>S content of the refinery plant gas to 60 ppm or less or reduce SO<sub>2</sub> concentration from fuel gas combustion devices to 8 ppmvd at 0% O<sub>2</sub> 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<sub>2</sub> 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. 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.

q. 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: Boilers (Each)

Pollutant	Oxygen Ref.	lb/hr
NO <sub>x</sub>	3%	3.3
PM <sub>2.5(Filterable)</sub>	3%	0.72

Source: Paper Machines Process Stacks (Each)

Pollutant	Oxygen Ref.	lb/hr
NO <sub>x</sub>	3%	13.50
PM <sub>2.5(Filterable)</sub>	3%	6.65

- 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. By no later than January 1, 2015, stack testing shall be completed to establish the ratio of condensable PM<sub>2.5</sub>. At that time the condensable fraction will be added and a PM<sub>2.5</sub> limit established in the AO.
- C. Subsequent to initial compliance testing, stack testing is required at a minimum of every three years.
- 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.

r. 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:

Emissions Point	Pollutant	ppmdv (3% O <sub>2</sub> dry)
A. Boilers #3	NO <sub>x</sub>	187
B. Boilers #4a & 4b*	NO <sub>x</sub>	9
C. Boilers #5a & 5b	NO <sub>x</sub>	9
D. Turbine	NO <sub>x</sub>	9
E. Turbine and WHRU Duct burner	NO <sub>x</sub>	15

\*Boiler #4 will be replaced with Boiler #4a and #4b by 2018.

- 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
A. Boilers #3	NO <sub>x</sub>	*	every 3 years
B. Boilers #4a & #4b	NO <sub>x</sub>	2018	every 3 years
C. Boilers #5a & #5b	NO <sub>x</sub>	2017	every 3 years
D. Turbine	NO <sub>x</sub>	*	every 3 years
E. Turbine and WHRU Duct Burner	NO <sub>x</sub>	*	every 3 years

Initial test already performed

\* 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.

# 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). 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. 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<sub>x</sub> burners or is replaced with a boiler that has low NO<sub>x</sub> burners. The burners shall have a NO<sub>x</sub> rating that are 9 ppm or less.

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

- t. Utah Municipal Power Association: West Valley Power Plant.
  - i. Total emissions of NO<sub>x</sub> from all five (5) catalytic-controlled turbines combined shall be no greater than 1050 lb of NO<sub>x</sub> 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. Total emissions of NO<sub>x</sub> from all five (5) catalytic-controlled turbines shall include the sum of all periods in the day including periods of startup, shutdown, and maintenance.
  - iii. The NO<sub>x</sub> emission rate (lb/hr) shall be determined by CEM. The CEM shall operate as outlined in IX.H.11.f.

u. Wasatch Integrated Waste Management District

Energy Recovery Facility

- i. By January 1, 2018, SNCR technology shall be installed and operating on each of the two Municipal Waste Combustors for the reduction of NO<sub>x</sub> emissions.
- ii. By January 1, 2018, emissions of NO<sub>x</sub> from the Municipal Waste Combustors shall not exceed 320 ppm<sub>dv</sub> (7% O<sub>2</sub>, dry basis), based on a 24-hour daily arithmetic average concentration.
  - A. Compliance with the NO<sub>x</sub> limitation shall be determined by operation of CEMS. The operation of the CEMS shall be in accordance with IX.H.11.f.
- iii. Emissions of SO<sub>2</sub> from the Municipal Waste Combustors shall not exceed 31 ppm<sub>dv</sub> (7% O<sub>2</sub>, dry basis), based on a 24-hour daily block geometric average concentration.
  - A. Compliance with the SO<sub>2</sub> limitation shall be determined by operation of CEMS. The operation of the CEMS shall be in accordance with IX.H.11.f.
- iv. Emissions of PM<sub>2.5</sub> from the Municipal Waste Combustors shall not exceed 27 milligrams (filterable) per dry standard cubic meter (Averaging Time: 3-run average), based on a run duration specified in the test method.
  - A. Compliance with the PM<sub>2.5</sub> limitation shall be determined by stack testing. The stack testing shall be done in accordance with IX.H.11.e.
- v. Gas Suspension Absorber (GSA) and PAC Injection
  - A. The control system for the GSA shall automatically shut-down or start-up the feeder screws, slurry pumps, and PAC feeder based upon minimum required gas flows and temperature.
  - B. The facility shall follow the Operations and Maintenance Manual shall ensure the GSA is operated as long as possible during startup/shutdown:
    - I. Cold Light Off  
The GSA is placed into startup sequence during final heating when the ESP inlet temperature reaches 285 degrees Fahrenheit and coincident to introducing MSW to the unit.
    - II. Hot Light Off  
The GSA is placed into startup sequence during final heating when the ESP inlet temperature reaches 285 degrees Fahrenheit and coincident to introducing MSW to the unit.
    - III. Secure to Hot  
Continue operations of the GSA after stopping feeding of refuse until ESP inlet temperature drops below 285 degrees Fahrenheit.

IV. Secure to Cold

Continue operations of the GSA after stopping feeding of refuse until ESP inlet temperature drops below 285 degrees Fahrenheit.

V. Malfunction Shut Down

Continue operations of the GSA after stopping feeding of refuse until ESP inlet temperature drops below 285 degrees Fahrenheit.

The GSA and PAC injection operations shall be recorded and documented in an operations log. The log shall record the hours operated, date, and time during start-up/shut-down events.

vi. Electrostatic Precipitator (ESP)

A. Each unit is equipped with an ESP for control of particulate emissions. The ESPs shall be operated in accordance with the facility Operations and Maintenance Manual. The facility Operations and Maintenance Manual shall ensure the ESP is operated as long as possible during start-up/shut-down:

I. Cold Light Off

The ESP is lined up and placed into operation prior to lighting burners and well before introducing MSW to the unit.

II. Hot Light Off

The ESP is lined up and placed into operation prior to lighting burners and well before introducing MSW to the unit.

III. Secure to Hot

Continue operations of the ESP throughout shutdown period as possible.

IV. Secure to Cold

Continue operations of the ESP throughout shutdown period as possible.

V. Malfunction Shut Down

Continue operations of the ESP throughout shutdown period as possible.

All operations of the ESPs shall be documented in an operations log. This log shall record the hours operated, date, and times during start-up/shut-down events.

Landfill Operation

- i. The owner/operator shall be subject to and comply with the requirements of 40 CFR 63 Subpart AAAA (National Emission Standards for Hazardous Air Pollutants: Municipal Solid Waste Landfills)

## H.13 Source-Specific Emission Limitations in Provo – UT PM<sub>2.5</sub> Nonattainment Area

a. Brigham Young University: Main Campus

- i. All central heating plant units shall operate on natural gas from November 1 to February 28 each season beginning in the winter season of 2013-2014. Fuel oil may be used as backup fuel during periods of natural gas curtailment. The sulfur content of the fuel oil shall not exceed 0.0015 % by weight. BYU must maintain a fuel specification certification document from the fuel supplier with the sulfur content guarantee. Alternatively, sulfur content may be verified through testing completed by BYU or the fuel supplier using ASTM Method D-4294-10 or EPA approved equivalent acceptable to the Director.
- ii. Emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

Emission Point	Pollutant	ppm (7% O <sub>2</sub> dry) *	lb/hr
A. Unit #1	NO <sub>x</sub>	95 36	9.55 5.44
B. Unit #4	NO <sub>x</sub>	127 36	38.5 19.2
C. Unit #6	NO <sub>x</sub>	127 36	38.5 19.2

\* Unit #1 NO<sub>x</sub> limit is 95 ppm (9.55 lb/hr) until it operates for more than 300 hours during a rolling 12-month period, then the limit will be 36 ppm (5.44 lb/hr). The NO<sub>x</sub> limit for units #4 and #6 is 127 ppm (38.5 lb/hr) and starting on December 31, 2018, the limit will then be 36 ppm (19.2 lb/hr).

Emission Point	Pollutant	ppm (7% O <sub>2</sub> dry)	lb/hr
D. Unit #2	NO <sub>x</sub>	331	37.4
	SO <sub>2</sub>	597	56.0
E. Unit #3	NO <sub>x</sub>	331	37.4
	SO <sub>2</sub>	597	56.0
F. Unit #5	NO <sub>x</sub>	331	74.8
	SO <sub>2</sub>	597	112.07

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

EMISSION POINT	POLLUTANT	INITIAL TEST	TEST FREQUENCY
A. Unit #1	NO <sub>x</sub>	&	every year*
B. Unit #2	NO <sub>x</sub>	#	every year*
C. Unit #3	NO <sub>x</sub>	#	every year*
D. Unit #4	NO <sub>x</sub>	#	every year*
E. Unit #5	NO <sub>x</sub>	#	every year*



v. Central Heating Plant Boilers

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

b. Geneva Nitrogen Inc.: Geneva Nitrogen Plant

i. Prill Tower:

PM<sub>10</sub> emissions (filterable and condensable) shall not exceed 0.236 ton/day  
PM<sub>2.5</sub> emissions (filterable and condensable) shall not exceed 0.196 ton/day

A day is defined as from midnight to the following midnight.

ii. Testing

A. Stack testing shall be performed as specified below:

I. Frequency: Emissions shall be tested every three years. The test shall be performed as soon as possible and in no case later than December 31, 2017.

B. The daily and rolling 12-month mass emissions shall be calculated by multiplying the most recent stack test results by the appropriate hours of operation for each day and for each rolling 12-month period.

iii. Montecatini Plant:

NO<sub>x</sub> emissions shall not exceed 30.8 lb/hr

iv. Weatherly Plant:

NO<sub>x</sub> emissions shall not exceed 18.4 lb/hr

v. Testing:

A. Stack testing for NO<sub>x</sub> shall be performed as specified below:

I. Stack testing to show compliance with the NO<sub>x</sub> emission limitations shall be performed as specified below:

1. Testing and Frequency. Emissions shall be tested every three years using an EPA approved test method.

II. NO<sub>x</sub> concentration (ppmdv) shall be used as an indicator to provide a reasonable assurance of compliance with the NO<sub>x</sub> emission limitation as specified below:

1. Measurement Approach: NO<sub>x</sub> concentration (ppmdv) shall be determined by using a continuous NO<sub>x</sub> monitoring system.

2. Performance Criteria:

i. QA/QC Practices and Criteria: The continuous monitoring system shall be operated, calibrated, and maintained in accordance with

manufacture's recommendations. Zero and span drift tests shall be conducted on a daily basis.

III. The EPA approved method test for the Montecatini Plant shall be performed as soon as possible and in no case later than December 31, 2017, and the test for the Weatherly Plant shall be performed as soon as possible and in no case later than December 31, 2018.

vi. Start-up/Shut-down

A. Startup / Shutdown Limitations:

- I. Planned shut-down and start-up events shall not exceed 50 hours per acid plant (Montecatini or Weatherly) per 12-month rolling period.
- II. Total startup and shutdown events shall not exceed four hours per acid plant in any one calendar day.

c. McWane Ductile - Utah

- i. Emissions of VOC from the finishing paint line shall not exceed 1 ton/day.
  - A. Compliance with the above conditions shall be demonstrated as follows: VOC emissions at the finishing paint line shall be determined by asphalt paint consumption. Asphalt paint consumption shall be monitored by liquid level monitoring sensors on the finishing paint line bulk tanks.
  - B. For purposes of this section a day is defined as a period of 24-hours commencing at midnight and ending at the following midnight.
- ii. The Annealing Oven furnaces are limited to 63.29 MMBtu/hr.
- iii. Emissions from the desulfurization and ductile treatment system shall be routed through the operating baghouse prior to be emitted into the atmosphere.
- iv. Emissions from the Special Lining Shotblast operations shall be routed through the operating baghouse prior to being emitted into the atmosphere.

- d. PacifiCorp Energy: Lake Side Power Plant
  - i. Block #1 Catalytic-controlled Turbine/HRSG Stacks:
    - A. Emissions of NO<sub>x</sub> shall not exceed 14.9 lb/hr on a 3-hr average basis
    - B. Compliance with the above conditions shall be demonstrated as follows:
      - I. NO<sub>x</sub> monitoring shall be through use of a CEM as outlined in IX.H.11.f
  - ii. Block #2 Catalytic-controlled Turbine/HRSG Stacks:
    - A. Emissions of NO<sub>x</sub> shall not exceed 18.1 lb/hr on a 3-hr average basis
    - B. Compliance with the above conditions shall be demonstrated as follows:
      - I. NO<sub>x</sub> monitoring shall be through use of a CEM as outlined in IX.H.11.f
  - iii. Startup / Shutdown Limitations:
    - A. Block #1:
      - I. Startup and shutdown events shall not exceed 613.5 hours per turbine per 12-month rolling period.
      - II. Total startup and shutdown events shall not exceed 14 hours per turbine in any one calendar day.
      - III. Cumulative short-term transient load excursions shall not exceed 160 hours per 12-month rolling period.
      - IV. During periods of transient load conditions, NO<sub>x</sub> emissions from the Block #1 Catalytic-controlled Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O<sub>2</sub>.
    - B. Block #2:
      - I. Startup and shutdown events shall not exceed 553.6 hours per turbine per 12-month rolling period.
      - II. Total startup and shutdown events shall not exceed 8 hours per turbine in any one calendar day.
      - III. Cumulative short-term transient load excursions shall not exceed 160 hours per 12-month rolling period.

IV. During periods of transient load conditions, NO<sub>x</sub> emissions from the Block #2 Catalytic-controlled Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O<sub>2</sub>.

C. Definitions:

- I. Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr emission limits listed in IX.H.13.d.i and ii above.
- II. Shutdown is defined as the period beginning with the initiation of turbine shutdown sequence and ending with the cessation of firing of the gas turbine engine.
- III. Transient load conditions are those periods, not to exceed four consecutive 15-minute periods, when the 15-minute average NO<sub>x</sub> concentration exceeds 2.0 ppmv dry @ 15% O<sub>2</sub>. Transient load conditions consist of the following:
  1. Initiation/shutdown of combustion turbine inlet air-cooling.
  2. Rapid combustion turbine load changes.
  3. Initiation/shutdown of HRSG duct burners.
  4. Provision of Ancillary Services and Automatic Generation Control.
- IV. For purposes of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

e. Payson City Corporation: Payson City Power

- i. Emissions of NO<sub>x</sub> shall be no greater than 1.54 ton per day for all engines combined.
- 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:

$$\text{Emissions (tons/day)} = (\text{Power production in kW-hrs/day}) \times (\text{Emission factor in grams/kW-hr}) \times (1 \text{ lb}/453.59 \text{ g}) \times (1 \text{ ton}/2000 \text{ lbs})$$

- A. The NO<sub>x</sub> emission factor for each engine shall be derived from the most recent stack test. Stack tests shall be performed in accordance with IX.H.11.e. Each engine shall be tested at least every three years from the previous test.
  - B. NO<sub>x</sub> emissions shall be calculated on a daily basis.
  - C. A day is equivalent to the time period from midnight to the following midnight.
  - D. The number of kilowatt hours generated by each engine shall be recorded on a daily basis with an electrical meter.
- iii. All engines shall be catalytic-controlled as outlined in IX.H.11.h.

f. Provo City Power: Power Plant

- i. NO<sub>x</sub> emissions from the operation of all engines at the plant shall not exceed 2.45 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:

$$\text{Emissions (tons/day)} = (\text{Power production in kW-hrs/day}) \times (\text{Emission factor in grams/kW-hr}) \times (1 \text{ lb}/453.59 \text{ g}) \times (1 \text{ ton}/2000 \text{ lbs})$$

- A. The NO<sub>x</sub> emission factor for each engine shall be derived from the most recent stack test. Stack tests shall be performed in accordance with IX.H.11.e. Each engine shall be tested every 8,760 hours of operation or at least every three years from the previous test, whichever occurs first.
  - B. NO<sub>x</sub> emissions shall be calculated on a daily basis.
  - C. A day is equivalent to the time period from midnight to the following midnight.
  - D. The number of kilowatt hours generated by each engine shall be recorded on a daily basis with an electrical meter.
- iii. All engines shall be catalytic-controlled as outlined in IX.H.11.h.

g. Springville City Corporation: Whitehead Power Plant

i. NO<sub>x</sub> emissions from the operation of all engines at the plant shall not exceed 1.68 tons per day.

ii. Internal combustion engine emissions shall be calculated from the operating data recorded by the CEM as outlined in IX.H.11.f. A day is equivalent to the time period from midnight to the following midnight. Emissions of NO<sub>x</sub> shall be calculated for each individual engine by the following equation:

$$D = (X * K)/453.6$$

Where:

X = grams/kW-hr rate for each generator (recorded by CEM)

K = total kW-hr generated by the generator each day (recorded by output meter)

D = daily output of pollutant in lbs/day

iii. All engines shall be catalytic-controlled as outlined in IX.H.11.h.