State of Utah

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DAQ-105-13

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Bill Reiss, Environmental Engineer

DATE: December 27, 2013

SUBJECT: FINAL ADOPTION: Add new SIP Subsections IX.H.11, 12, and 13. Control Measures for Area and Point Sources, Emission Limits and Operating Practices, $PM_{2.5}$ Requirements.

On December 14, 2009, the Environmental Protection Agency (EPA) made its designations concerning areas that were not attaining the 2006 National Ambient Air Quality Standards (NAAQS) for $PM_{2.5}$. Among those areas designated were the Salt Lake City, UT $PM_{2.5}$ nonattainment area and the Provo, UT $PM_{2.5}$ nonattainment area.

The Clean Air Act requires Utah to submit a nonattainment plan for each of these areas. Those plans must provide for the implementation of all reasonable control measures and include enforceable emission limitations and other control measures as well as schedules and timetables for compliance.

On October 2, 2013, the Board proposed for public comment SIP Subsections IX.H.11, 12, and 13, which address the requirement to include emission limitations, control measures, and schedules for certain large stationary sources. Subsection 11 includes general provisions that apply to sources listed in either nonattainment area, while subsections 12 and 13 apply to specific sources located in the Salt Lake City and Provo nonattainment areas, respectively.

A 30-day public comment period was held, including two public hearings. A summary of the comments received during the comment period and the responses from DAQ is attached. Note that some of these comments pertain to the SIP narratives for these nonattainment areas (SIP sections IX.A. 21 and 22) that were approved by the Utah Air Quality Board last month.

Among the most critical of the comments DAQ received was a suggestion by EPA Region VIII that they cannot approve language used throughout Subsection IX.H.11, 12, and 13 exempting emissions during startup, shutdown, and malfunction from the emission limits contained in Subsection IX.H. As DAQ has been working with EPA and the sources on this language, it became apparent that resolving this issue during this iteration of the SIP is not possible due to rulemaking requirements, etc. Therefore, DAQ will address this issue during the development of the Subpart IV SIP during the coming six months.

Any recommended revisions to SIP Subsections IX.H.11, 12, and 13 resulting from these comments are identified in the amended attachment using strikeout and underline.

Staff Recommendation: Staff recommends the Board adopt SIP Subsection IX.H.11, 12, and 13. Control Measures for Area and Point Sources, Emission Limits and Operating Practices, $PM_{2.5}$ Requirements as amended.

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

a. Except as otherwise outlined in individual conditions of this Subsection IX.H.11 listed below, [~~The~~]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 two subsections, the source specific conditions listed in IX.H.12 and 13 shall take precedence.

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

c. 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.

d. All emission limitations listed in Subsections IX.H.12 and IX.H.13 apply during steady-state operation, unless otherwise specified in the source specific conditions listed in IX.H.12 and 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 methods acceptable to the Director.

B. Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2 [~~or EPA Test Method No. 19 "SO_2 Removal & PM, SO_2, NO_x Rates from Electric Utility Steam Generators"~~]or other EPA-approved testing methods acceptable to the Director.

C. PM_{10}: [~~For stacks in which no liquid drops are present, the following methods shall be used:~~]40 CFR 51, Appendix M, Methods [~~201,~~]201a and 202, or other EPA approved testing methods acceptable to the Director. [~~All particulate captured shall be considered PM_{10}. The back half condensables shall be used for compliance demonstration as well as for inventory purposes. For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5A, 5B, 5D,5E, 5F, or 5I as appropriate, or other EPA-approved testing methods acceptable to the Director. The back half condensables shall also be tested using the method specified by the Director.~~]If a method other than 201a is used, t[~~T~~]he 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.

D. $PM_{2.5}$: [~~For stacks in which no liquid drops are present, the following methods shall be used:~~]40 CFR 51, Appendix M, 201a and 202, or other EPA approved testing methods acceptable to the Director. [~~All particulate captured shall be considered $PM_{2.5}$.~~]The back half condensables shall be used for compliance demonstration as well as for inventory purposes. [~~For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5A, 5B, 5D,5E, 5F, or 5I as appropriate, or other EPA-approved testing methods acceptable to the Director.~~]If a method other than 201a is used, t[~~T~~]he[~~ back half condensables shall also be tested using the method specified by the Director. The~~] portion of the front half of the catch considered $PM_{2.5}$ shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.

E. SO_2: 40 CFR 60 Appendix A, Method [~~6, 6A, 6B,~~]6C[~~,~~] or other EPA-approved testing methods acceptable to the Director.

F. NO_x: 40 CFR 60 Appendix A, Method [~~7, 7A, 7B, 7C, 7D,~~]7E[~~,~~] or other EPA-approved testing methods acceptable to the Director.

G. VOC: 40 CFR 60 Appendix A, Method 25A or EPA-approved testing methods acceptable to the Director.

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

I. [~~Notification of the test date~~]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. 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.

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.

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

g. Petroleum Refineries.

i. Limits at Fluid Catalytic Cracking Units

A. FCCU SO_2 Emissions

I. By no later than January 1, 2018, each owner or operator of an FCCU shall comply with an SO_2 emission limit of 25 ppmvd @ 0% excess air on a 365-day rolling average basis and 50 ppmvd @ 0% excess air on a 7-day rolling average basis.

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

III. SO_2 emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the emission limits in I., II. above provided that during such periods the owner or operator implements good air pollution control practices to minimize SO_2 emissions.[~~SO_2 emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the emission limit of 50 ppmvd @ 0% excess O_2 on a 7-day rolling average basis, provided that during such periods the owner or operator implements good air pollution control practices to minimize SO_2 emissions.~~]

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. PM emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the emission limit of 1.0 pounds of PM per 1000 pounds of coke burned on a 3-hour average basis, provided that during such periods the owner or operator implements good air pollution control practices to minimize PM emissions.

IV. <u>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 $PM_{2.5}$ emissions as appropriate.</u>

ii. Limits on Refinery Fuel Gas.

A. By no later than January 1, 2018, all petroleum refineries in or affecting the $PM_{2.5}$ nonattainment area shall reduce the H_2S content of the refinery plant gas to 60 ppm or less as described in 40 CFR 60.102a, except during periods of startup, shutdown, or malfunction. 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, 2018. 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, 2018.

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 $PM_{2.5}$ 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 $PM_{2.5}$ non-attainment area within the State shall install and operate a flare gas recovery system designed to limit hydrocarbon flaring from each affected flare to levels below the values listed in 40 CFR 60.103a(c), except during periods of startup, shut down, or malfunction. Flare gas recovery is not required for dedicated SRU flares, SRU flare header systems, nor HF flare 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.

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

a. ATK Launch Systems Inc. – Promontory

i. During the period November 1 to February 28/29 on days when the 24-hour average $PM_{2.5}$ levels exceed 35 ug/m^3at 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 $PM_{2.5}$ 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 $PM_{2.5}$ levels exceed 35 ug/m3 at the nearest real-time monitoring station, the following shall not be tested:

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

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

I. A single test of rocket motors less than 1,000,000 lbs. of propellant per motor is allowed on a day when the 24-hour average $PM_{2.5}$ level[~~s~~] exceeds 35 ug/m^3 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 $PM_{2.5}$ level[~~s~~] has[~~ve~~] returned to a concentration below 35 ug/m^3 at the nearest real-time monitoring station.

iii. During this period, records will be maintained identifying the size of the rocket motors tested and the 24-hour average $PM_{2.5}$ level at the nearest real-time monitoring station on days when [~~open burning~~]motor testing occur

iv. After January 1, 2017, ATK shall either upgrade the two 71 MMBTU/hr boilers operated in Building M576 so that they have a NO_x emission rate not greater than 30 ppm or replace them with boilers that have a NO_x emission rate less than 30 ppm.

b. Big West Oil Refinery

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

Following installation of the Flue Gas Blow Back Filter (FGF), but no later than January 1, 2019, [~~Big West Oil's maximum~~]combined emissions of filterable $PM_{2.5}$ [~~emissions to the atmosphere~~]shall not exceed 0.18 tons per day and 45 tons per rolling 12-month period[~~ for the entire refinery~~]. By no later than January 1, 2019, Big West Oil shall conduct stack testing to establish the ratio of condensable $PM_{2.5}$ from the Catalyst Regeneration System. At that time the condensable fraction will be added and a new source-wide limitation shall be established in the AO.

$PM_{2.5}$ emissions shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed above, the default emission factors to be used are as follows:[~~Filterable~~ ~~$PM_{2.5}$~~ ~~emissions shall be determined daily by applying various emission factors to the relevant quantities of fuel combusted. Unless otherwise specified by an Approval Order issued to Big West Oil, the default emission factors to be used are as follows:~~]

Natural gas – 1.9 lb/MMscf (filterable), 5.7 lb/MMscf (condensable)
Plant gas – 1.9 lb/MMscf (filterable), 5.7 lb/MMscf (condensable)

Daily gas consumption by all boilers and furnaces shall be measured by meters that can delineate the flow of gas to the indicated emission points.

The equations 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)

The daily filterable $PM_{2.5}$ emissions from the Catalyst Regeneration System shall be calculated using the following equation:

E = FR * EF

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

Total 24-hour filterable $PM_{2.5}$ emissions shall be calculated by adding the results of the above filterable $PM_{2.5}$ equations for natural gas and plant gas combustion to the estimate for the Catalyst Regeneration System. Results shall be tabulated every day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

ii. Source-wide NO_x

By no later than January 1, 2019, combined emissions of NO_x shall not exceed 0.80 tons per day (tpd) and 195 tons per rolling 12-month period.[~~ Big West Oil's maximum~~ ~~NO_x~~

~~emissions to the atmosphere shall not exceed 0.80 tons per day and 195 tons per rolling 12-month period for the entire refinery.~~]

NO_x emissions shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed above, the default emission factors to be used are as follows:[~~NO_x emissions shall be determined daily by applying various emission factors to the relevant quantities of fuel combusted. Unless otherwise specified by an Approval Order issued to Big West Oil, the default emission factors to be used are as follows:~~]

Natural gas – latest version of AP-42 (currently see AP-42, Table 1.4-1)
Plant gas – assumed equal to natural gas (use values from AP-42, Table 1.4-1)

Since the emission factors are considered to be the same for either gas, this factor shall be applied to the metered quantity of blended gas. Should future information reveal that there is a difference in the emission factors for natural gas and plant gas, then the respective quantities shall be delineated in the AO.

[~~Daily gas consumption by all boilers and furnaces shall be measured by meters that can delineate the flow of gas to the indicated emission points.~~]Daily plant gas consumption at the furnaces and boilers shall be measured by flow meters.

The equations 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)

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

NO_x = (Flue Gas, moles/hr) x (ADV ppm /10^6) x (30.006 lb/mole) x (operating hr/day)/(2000 lb/ton)

Where ADV = average daily value from NO_x CEM

Total daily NO_x emissions shall be calculated by adding the results of the above NO_x equations for natural gas and plant gas combustion to the estimate for the Catalyst Regeneration System. Results shall be tabulated every day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

iii. Source-wide SO_2

By no later than January 1, 2019, combined emissions of [~~Big West Oil's maximum SO_2 emissions to the atmosphere~~]shall not exceed 0.60 tons per day and 140 tons per rolling 12-month period[~~ for the entire refinery~~].

SO_2 emissions shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed above, the default emission factors to be used are as follows:[~~SO_2 emissions shall be determined daily by applying various emission factors to the relevant quantities of fuel combusted. These emission factors are:~~]

Natural Gas - 0.60 lb SO_2/MMscf gas

Plant Gas - The emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a continuous emissions monitor, which shall measure the H_2S content of the fuel gas in ppmv. Daily emission factors shall be calculated using average daily H_2S content data from the CEM. The emission factor shall be calculated as follows:

Emission Factor (lb SO_2/MMscf gas) = [(24 hr avg. ppmv H_2S)/10^6]*(64 lb SO_2/lb mole)*[(10^6 scf/MMscf)/(379 scf/lb mole)]

Daily natural gas consumption shall be measured by the two meters that supply the refinery.

Daily plant gas consumption at the furnaces and boilers shall be measured by flow meters.[~~Daily plant gas consumption shall be measured by whatever meters are necessary to measure the flow of plant gas throughout the plant.~~]

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

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

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

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

SO_2 = FG * (ADV/1,000,000) * (64 lb/mole) * (operating hours/day) / (2000 lb/ton)

Where:
FG = Flue Gas in moles/hour
ADV = average daily value from SO_2 CEM

Total daily SO_2 emissions shall be calculated by adding the daily results of the above SO_2 emissions equations for natural gas and plant gas combustion to the estimate for the Catalyst Regeneration System. Results shall be tabulated every day, and records shall be kept which include the CEM readings for H_2S (averaged for each day), all meter readings (in the appropriate units), and the calculated emissions.

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_x 0.6 g/kW-hr

B. GT #2 and GT #3 (each TITAN Turbine) Exhaust Stack:
NO_x 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. Each turbine shall be tested at least once per year.

d. CER Generation II, LLC (Exelon Generation): West Valley Power Plant

i. Emissions of NO_x from each individual turbine shall be no greater than 5 ppmdv (15% O_2, dry) based on a 30-day rolling average.

ii. Total emissions of NO_x from all five turbines shall be no greater than 37 lbs/hour (15% O_2, dry) based on a 30-day rolling average.

iii. The NO_x emission rate (lb/hr) shall be calculated by multiplying the NO_x concentration (ppmdv) generated from CEMs and the volumetric flow rate. The 30-day rolling average shall be calculated by adding previous 30 days data on a daily basis.

e. Central Valley Water Reclamation Facility: Wastewater Treatment Plant

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

Compliance with the daily mass emission limits shall be demonstrated by multiplying emission factors (in units of mass per kw-hr) determined for each engine by the most recent stack test results, by the respective kilowatt hours generated each day. Power production shall be determined by examination of electrical meters which shall record the electricity production. Continuous recording is required. The records shall be kept on a daily basis.

NO_x emission from the operation of all engines at the plant shall not exceed 205.6 tons per calendar year.

Stack testing to determine the emission factors necessary to show compliance with the emission limitations stated in this condition shall be performed at least once every five (5) years.

ii. Emissions to the atmosphere from each of the 1150 kw engine generators shall not exceed the following rates and concentrations:

Pollutant	lb/hr	gm/(hp-hr)
NO_x	5.95	1.75

iii. Emissions to the atmosphere from each of the 1340 kw engine generators shall not exceed the following rates and concentrations:

Pollutant	lb/hr	gm/(hp-hr)
NO_x	7.13	1.8

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

f. Chemical Lime Company (LHoist North America)

i. Lime Production Kiln:

A. Upon source start-up SNCR technology shall be installed on the Lime Production Kiln for reduction of NO_x emissions.

B. Upon source start-up a baghouse control technology shall be installed and operating on the Lime Production Kiln for reduction of PM emissions.

I. PM emissions shall not exceed 0.12 pounds per ton (lb/ton) of stone feed

II. Compliance with the above emission limit 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.

C. An initial compliance test is required within 180 days of source start-up.

D. Subsequent to initial compliance testing, stack testing is required at a minimum of every five years.

g. Chevron Products Company - Salt Lake Refinery

i. Source-wide $PM_{2.5}$

By no later than January 1, 2019, [~~Combined~~]combined emissions of filterable $PM_{2.5}$ shall not exceed 0.18 tons per day (tpd) and 65 tons per rolling 12-month period.

Compliance with the daily $PM_{2.5}$ limit shall be determined daily by multiplying the quantity of each fuel burned at the affected units by the associated emission factor for that fuel, and summing the results.

$PM_{2.5}$ emissions shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed above, the default emission factors to be used are as follows:[~~Filterable $PM_{2.5}$ emissions shall be determined daily by applying various emission factors to the relevant quantities of fuel combusted. Unless otherwise specified by an Approval Order issued to Chevron, the default emission factors to be used are as follows:~~]

Natural gas – 1.9 lb/MMscf (filterable), 5.7 lb/MMscf (condensable)
Plant gas – 1.9 lb/MMscf (filterable), 5.7 lb/MMscf (condensable)

Fuel Oil/ HF alkylation polymer: The filterable $PM_{2.5}$ emission factor shall be determined based on the sulfur content of the fuel (S) according to the equation:

EF (lb/1000 gal) = (Wt. % S * 10) + 3.22

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

[~~Daily gas consumption by all boilers and furnaces shall be measured by meters that can delineate the flow of gas to the indicated emission points.~~]Daily plant gas consumption at the furnaces and boilers shall be measured by flow meters.

Daily fuel oil consumption shall be monitored with tank gauges. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

The filterable $PM_{2.5}$ emission factor for the FCC Catalyst Regenerator shall be determined based on the results of the most recent stack test.

By no later than January 1, 2017, Chevron shall conduct stack testing to establish the ratio of condensable $PM_{2.5}$ from the FCC Catalyst Regenerator and SRUs. At that time the condensable fraction will be added and a new source-wide limitation shall be established in the AO.

ii. Source-wide NO_x

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

Compliance with the daily limit shall be determined daily by multiplying the quantity of each fuel burned at each affected unit by the associated emission factor for that fuel at that unit, and summing the results.

Chevron shall maintain a record of fuel meter identifiers and locations, conversion factors, and other information required to demonstrate the required calculations. Records shall be kept showing the daily fuel usage, fuel meter readings, required fuel properties, hours of equipment operation, and calculated daily emissions.

The emission factors to be used for the above limitations are as follows:

Natural Gas/Plant Gas: by individual furnace/boiler*

*the most recent listing of these emission factors is maintained in Chevron's AO.

FCC Regenerator: The emission rate shall be determined by the FCC Regenerator NO_x CEM

All other emission units shall be stack-tested if directed by the Director. Chevron may also perform a stack test to provide information for updating the emission factors.

iii. Source-wide SO_2

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

Daily SO_2 emissions from affected units shall be determined by multiplying the quantity of each fuel used daily (24 hr usage) at each affected unit by the appropriate emission factor below. The values shall be summed to show the total daily sulfur dioxide emission.

Emission factors (EF) for the various fuels and emission [~~emission~~]points shall be as follows:

FCC Regenerator: The emission rate shall be determined by the FCC Regenerator SO_2 CEM

SRUs: The emission rate shall be determined by multiplying the sulfur dioxide concentration in the flue gas by the mass flow of the flue gas. The sulfur dioxide concentration in the flue gas shall be determined by CEM.

Natural gas: EF = 0.60 lb/MMscf

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

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

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

EF (lb SO_2/MMscf gas) = (24 hr avg. ppmdv H_2S) /10^6 * (64 lb SO_2/lb mole) * (10^6 scf/MMscf)/(379 scf/lb mole)

Chevron shall maintain a record of fuel meter identifiers and locations, conversion factors, and other information required to demonstrate the required calculations. Records shall be kept showing the daily fuel usage, fuel meter readings, required fuel properties, hours of equipment operation, and calculated daily emissions.

h. Great Salt Lake Minerals Corporation: Production Plant[

~~i. PM_{10} emissions to the atmosphere from the indicated emission point shall not exceed the following concentrations:~~

~~Emission Point~~	~~Concentration (grains/dscf) (@ 68 degrees F 29.92 in Hg)~~
~~SOP Plant Compaction/Loadout~~	~~0.010~~
~~Salt Plant Screening~~	~~0.010~~
~~SOP Plant Dryer D-001~~	~~0.010~~
~~SOP Plant Dryer D-002~~	~~0.010~~
~~SOP Plant Dryer D-003~~	~~0.010~~
~~SOP Plant Dryer D-004~~	~~0.010~~
~~SOP Plant Drying Circuit Fluid Bed Heater D-005~~	~~0.010~~
~~Salt Plant Dryer D-501~~	~~0.010~~
~~SOP Loadout~~	~~0.010~~
~~SOP Silo Dust Collection~~	~~0.010~~
~~SOP Plant Compaction~~	~~0.010~~
~~Salt Plant Dust Collection~~	~~0.010~~
~~Bulk Truck Salt Loadout~~	~~0.0053~~
~~Mag Chloride Plant~~	~~0.010~~]

i. NO_x 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

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. A compliance test shall be performed at least once every three years subsequent to the initial compliance test.

ii. PM_{10} 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 Plant Compaction/Loadout	0.01
Salt Plant Screening	0.01
SOP Plant Dryer D-001	0.01
SOP Plant Dryer D-002	0.01
SOP Plant Dryer D-003	0.01
SOP Plant Dryer D-004	0.01
SOP Plant Drying Circuit Fluid Bed Heater D-005	0.01
Salt Plant Dryer D-501	0.01

a. Compliance to the above emission limits shall be determined by stack test as outlined in Section IX Part H.11a of this SIP. The stack test date shall be performed as soon as possible and in no case later than January 1, 2017. A compliance test shall be done at least once every three years subsequent to the initial compliance test.

b. Within one hundred and twenty (120) days after the initial compliance test date required above for each baghouse/scrubber, GSLM shall submit a Notice of Intent to DAQ in which a $PM_{2.5}$ emission limit in grains/dscf and pounds/hour is proposed.

iii. PM_{10} 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.11a of this SIP. The stack test date shall be performed as soon as possible and in no case later than January 1, 2017. A compliance test shall be done at least once every five years subsequent to the initial compliance test.

b. Within one hundred and twenty (120) days after the initial compliance test date required above for each baghouse/scrubber, GSLM shall submit a Notice of Intent to DAQ in which a $PM_{2.5}$ emission limit in grains/dscf and pounds/hour is proposed.

iv. By January 1, 2017, Low NOx burner technology with a minimum manufacturer guarantee of 77% NOx removal efficiency shall be in operation on all dryers.[

~~Stack tests shall be performed as soon as possible and in no case later than January 1, 2017.~~

~~Subsequent to initial compliance testing, stack testing is required at a minimum of every five years.~~

~~By January 1, 2017, at a minimum, ultra-low NO_x burner technology shall be in operation on all dryers.~~]

i. Hexcel Corporation: Salt Lake Operations

i. The following limits shall not be exceeded for Fiber Lines 2-8, 10-16, the Pilot Plant, and Matrix Operations:

A. 4.42 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.

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.

j. Hill Air Force Base: Main Base

i. VOC emissions from painting and depainting operations shall not exceed 0.5 tons per day.

ii. Compliance with this daily average shall be determined monthly.

k. HollyFrontier Corporation: Holly Refining [~~&~~]and Marketing Company – Woods Cross L.L.C. (Holly Refinery)

i. Source-wide $PM_{2.5}$

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

$PM_{2.5}$ emissions shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed above, the default emission factors to be used are as follows:[~~$PM_{2.5}$ emissions shall be determined daily by applying various emission factors or emission factors determined from the most current performance testing to the relevant quantities of fuel combusted. Unless otherwise specified by an Approval Order issued to Holly, the default emission factors to be used are as follows:~~]

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

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

$PM_{2.5}$ (lb/1000 gal) = (10 * wt. % S) + 3.22

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

Daily natural gas and plant gas consumption shall be determined through the use of flow meters on all gas-fueled combustion equipment.[~~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 [~~gage~~]gauges on all tanks that supply fuel oil to combustion sources. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

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)

Total 24-hour $PM_{2.5}$ emissions for the emission points shall be calculated by adding the daily results of the above $PM_{2.5}$ emissions equations for natural gas, plant gas, and fuel oil combustion. Results shall be tabulated for every day, and records shall be kept which include all meter readings (in the appropriate units), fuel oil parameters (wt. %S), and the calculated emissions.

ii. Source-wide NO_x

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

NO_x emissions shall be determined by applying the following emission factors or emission factors determined from the most current performance testing to the relevant quantities of fuel combusted.

Natural gas/refinery fuel gas combustion using Low NO_x burners (LNB): 41 lbs/MMscf
Natural gas/refinery fuel gas combusted using Ultra-Low NO_x burners: 0.04 lbs/MMbtu
Natural gas/refinery fuel gas combusted using Next Generation Ultra Low NO_x burners: 0.10 lbs/MMbtu
Natural gas/refinery fuel gas combusted burners using selective catalytic reduction (SCR): 0.02 lbs/MMbtu
All other natural gas/refinery fuel gas combustion burners: 100 lb/MMscf
All fuel oil combustion: 120 lbs/Kgal

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.

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. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

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

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

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

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

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

Total daily NO_x emissions for emission points shall be calculated by adding the results of the above NO_x equations for plant gas, fuel oil, and natural gas combustion. Results shall be tabulated for every day; and records shall be kept which include the meter readings (in the appropriate units), emission factors, and the calculated emissions.

iii. Source-wide SO_2

By no later than January 1, 2019, [~~T~~]the emission of SO_2 [~~into the atmosphere~~]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).

The routine turnaround maintenance period (a maximum of once every three years for a maximum of a 15 day period) for the SRU (Unit 17) shall only be scheduled during the period of April 1 through October 31. The projected SRU turnaround period shall be submitted to the Director by April 1 of each year in which a turnaround is planned. Notice shall also be provided to the Director 30 days prior to the planned turnaround.

SO_2 emissions into the atmosphere shall be determined by applying the following emission factors or emission factors determined from the most current performance testing to the relevant quantities of fuel burned. SO_2 emission factors for the various fuels shall be as follows:

Natural gas - 0.60 lb SO_2/MMscf

Plant gas - The emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a CEM which will measure the H_2S content of the fuel gas in parts per million by volume (ppmv). Daily emission factors shall be calculated using average daily H_2S content data from the CEM. The emission factor shall be calculated as follows:

(lb SO_2/MMscf gas) = (24 hr avg. ppmv H_2S)/10^6 * (64 lb SO_2/lb mole) * (10^6 scf/MMscf)/(379 scf / lb mole)

Fuel oil - The emission factor to be used in conjunction with fuel oil combustion (during natural gas curtailments) shall be calculated based on the weight percent of sulfur, as determined by ASTM Method 0-4294-89 or EPA-approved equivalent, and the density of the fuel oil, as follows:

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

The weight percent sulfur and the fuel oil density shall be recorded for each day any fuel oil is combusted. Fuel oil may be combusted only during periods of natural gas curtailment. [~~The sulfur content of the fuel oil shall be tested if directed by the Director.~~]

Fuel Consumption shall be measured as follows:

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

Fuel oil consumption shall be measured each day by means of leveling gauges on all tanks that supply oil to combustion sources.

The equations used to determine emissions shall be as follows:

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

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

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

Total daily SO_2 emissions shall be calculated by adding daily results of the above SO_2 emissions equations for natural gas, plant gas, and fuel oil combustion. Results shall be tabulated for every day; and records shall be kept which include the CEM readings for H_2S (averaged for each one-hour period), all meter readings (in the appropriate units), fuel oil parameters (density and wt. %S, recorded for each day any fuel oil is burned), and the calculated emissions.

l. 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.

B. The following source-wide emission limits at the BCM shall not be exceeded:

I. 6,205 tons of NO_X, $PM_{2.5}$ and SO_2 combined per rolling 12-month period until January 1, 2019.

II. After January 1, 2019, combined emissions of NO_X, $PM_{2.5}$, and SO_2 shall not exceed 5,585 tons per rolling 12 month period.

Compliance with the 12-month period limits shall be determined on a rolling 12-month total based on the previous 12 months per methodology outlined in Emissions Inventory. KUC shall calculate a new 12-month total by the 20th day of each month using data from the previous 12 months. [R307-401-8]

C. 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 conditions warrant, and shall

1. ensure the surface of the active haul roads located within the pit influence boundary consists of road base material, blasted waste rock, crushed rock, or chemical dust suppressant, and

2. apply a chemical dust suppressant to active haul roads located outside of the pit influence boundary no less than twice per year.

II. Ore conveyors shall be the primary means for transport of crushed ore from the mine to the concentrator.

III. Chemical dust suppressant shall be applied as conditions warrant on unpaved access roads that receive haul truck traffic and light vehicle traffic.

[~~IV. Graders shall be used to perform haul road maintenance and clean-up activities as well as other operational functions.~~]

m. 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 shall not exceed the following emission rates to the atmosphere:

	POLLUTANT	lb/hr	ppmdv (15% O2 dry)
I.	NO_x:		2.0*
II.	VOC:		2.0*
III.	$PM_{2.5}$ with duct firing:		
	Filterable + condensable	18.8	

* Under steady state operation.

C. Stack testing to show compliance with the above Unit #5 emission limitations shall be performed as follows:

	POLLUTANT	TEST FREQUENCY
I.	$PM_{2.5}$	3 years
II.	NO_x	3 years
III.	VOC	3 years

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 steady state operation and does not require stack testing.~~]

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

I. During the period from November 1, to the last day in February inclusive, 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.

II. Except during a curtailment of natural gas supply, emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:

POLLUTANT	grains/dscf 68°F, 29.92 in. Hg	ppmdv (3% O^2)
1. Before January 1, 2018		
a. $PM_{2.5}$		
filterable	0.004	
filterable + condensable	0.03	
b. NO_x:		336
2. After January 1, 2018		
a. $PM_{2.5}$		
filterable	0.004	
filterable + condensable	0.03	
b. NO_x:		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 68°F, 29.92 in Hg	lb/hr	ppmdv (3% O_2)
1. $PM_{2.5}$			
filterable	0.029	33.5	
filterable + condensable	0.29	382	
2. NO_x			384

IV. Stack testing to show compliance with the emission limitations in H.12.m.i.D.II and III shall be performed as follows for the following air contaminants:

POLLUTANT	TEST FREQUENCY
1. $PM_{2.5}$	every year
2. NO_x	every year

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.

ii. BONNEVILLE BORROW AREA PLANT

A. Maximum total mileage per day for haul trucks shall not exceed 12,500 miles.

n. Kennecott Utah Copper: Smelter and Refinery

i. SMELTER:

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

I. Main Stack (Stack No. 11)

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

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

3. NO_x 35 lbs/hr (annual average)

II. Acid Plant Tail Gas

1. SO_2
   a. 1,050 ppmdv (3 hr. rolling average)
   b. 650 ppmdv (6 hr. rolling average)

III. Holman Boiler

1. NO_x
   a. 9.34 lbs/hr, 30-day average
   b. 0.05 lbs. MMBTU, 30-day average

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

EMISSION POINT	POLLUTANT	TEST FREQUENCY
I. Main Stack (Stack No. 11)		
	$PM_{2.5}$	every year
	SO_2	CEM
	NO_x	CEM
II. Acid Plant Tailgas	SO_2	CEM

III. Holman Boiler	NO_x	CEM or alternate method determined according to applicable NSPS standards

ii. REFINERY:

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

EMISSION POINT	POLLUTANT	MAXIMUM EMISSION RATE
The sum of two (Tankhouse) Boilers	NO_x	9.5 lbs/hr
Combined Heat Plant	NO_x	5.96 lbs/hr

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

EMISSION POINT	POLLUTANT	TESTING FREQUENCY
Tankhouse Boilers	NO_x	every three years
Combined Heat Plant	NO_x	every year

To determine mass emission rate, 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. Provided that the two boilers installed are identical in make, model, and pollution control equipment, compliance with the emission limitation by the second boiler shall be determined by the stack test of the first boiler.

C. The owner/operator shall use only natural gas or landfill gas as a primary fuel in the boilers. The boilers may be equipped to operate on #2 fuel oil; however, operation of the boilers on #2 fuel oil shall only occur during periods of natural gas curtailment and during testing and maintenance periods. Operation of the boilers on #2 fuel oil shall be reported to the Director within one working day of start-up. Emissions resulting from operation of the boiler on #2 fuel oil shall be reported to the Director within 30 days following the use of #2 fuel oil in the boilers.

iii. MAP:

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

EMISSION POINT	POLLUTANT	MAXIMUM EMISSION RATE
Combined Heat Plant	NO_x	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_x	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.

o. Nucor Steel Mills

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

A. Electric Arc Furnace Baghouse

I. $PM_{2.5}$
1. 19.53 lbs/hr (24 hr. average filterable)
2. 29.53 lbs/hr (filterable + condensable)

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

III. NO_x 59.75 lbs/hr (12-month rolling average)

IV. VOC 22.20 lbs/hr

B. Reheat Furnace #1

NO_x 15.0 lb/hr

C. Reheat Furnace #2

NO_x 8.0 lb/hr

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

EMISSION POINT	POLLUTANT	TEST FREQUENCY
A. Electric Arc Furnace Baghouse	$PM_{2.5}$	every year
	SO_2	CEM
	NO_X	CEM
	VOC	every 5 years
B. Reheat Furnace #1	NO_x	every 3 years
C. Reheat Furnace #2	NO_x	every 3 years

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

A. To demonstrate compliance with the Electric Arc Furnace stack mass emissions limits for

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

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

p. Olympia Sales Company: Cabinet Manufacturing Facility

i. By January 1, 2015, a baghouse control device shall be installed and operating for control of PM from the process exhaust streams from the mill, door, and sanding areas.

q. PacifiCorp Energy: Gadsby Power Plant

i. Steam Generating Unit #1:

A. Emissions of NO_x shall be no greater than 336 ppmdv (3% O_2, dry).

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

ii. Steam Generating Unit #2:

A. Emissions of NO_x shall be no greater than 336 ppmdv (3% O_2, dry).

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

iii. Steam Generating Unit #3:

A. Emissions of NO_x shall be no greater than 336 ppmdv (3% O_2, dry).

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

iv. Natural Gas-fired Simple Cycle Turbine Units:

A. Total emissions of NO_x from all three turbines shall be no greater than 22.2 lbs/hour (15% O_2, dry) based on a 30-day rolling average.

B. Emission of NO_x from each individual turbine shall be no greater than 5 ppmdv (15% O_2, dry) based on 30 day rolling average.

C. The owner/operator[~~permittee~~] shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_x and O_2 monitors to determine compliance with the applicable NO_x limitations. The NO_x emission rate (lb/hr) shall be calculated by multiplying the NO_x concentration (ppmdv) generated from CEMs and the volumetric flow rate.

D. The owner/operator shall expand the catalyst beds to achieve additional NOx control on Natural Gas-fired Simple Cycle Turbine Units (Units #4, #5 and #6) by no later than January 1, 2017.

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

i. Source-wide $PM_{2.5}$

By no later than January 1, 2019, combined emissions of filterable PM2.5 shall not exceed 0.42 tons per day (tpd) and 110 tons per rolling 12-month period.[~~Tesoro's maximum filterable $PM_{2.5}$ emissions to the atmosphere shall not exceed 0.42 tons per day (tpd) and 110 tons per rolling 12-month period for the entire refinery.~~]

[~~Filterable~~]$PM_{2.5}$ emissions shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed above, the default emission factors to be used are as follows:[~~emissions shall be determined daily by applying various emission factors to the relevant quantities of fuel combusted. Unless otherwise specified by an Approval Order issued to Tesoro, the default emission factors to be used are as follows:~~]

Natural gas – 1.9 lb/MMscf (filterable), 5.7 lb/MMscf (condensable)
Plant gas – 1.9 lb/MMscf (filterable), 5.7 lb/MMscf (condensable)

Daily gas consumption by all boilers and furnaces shall be measured by meters that can delineate the flow of gas to the indicated emission points.

The equations 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)

By no later than January 1, 2019, Tesoro shall conduct stack testing to establish the ratio of condensable $PM_{2.5}$ from the FCCU wet gas scrubber stack[~~ and SRU/TGTU/TGI~~]. At that time the condensable fraction will be added and a new source-wide limitation shall be established in the AO.

Total 24-hour $PM_{2.5}$ (filterable + condensable) emissions shall be calculated by adding the results of the above filterable $PM_{2.5}$ equations for natural gas and plant gas combustion to the values for the FCCU wet gas scrubber stack and to the estimate for the SRU/TGTU/TGI. Results shall be tabulated every day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

ii. Source-wide NO_x

By no later than January 1, 2019, [~~Combined~~]combined emissions of NO_x shall not exceed [~~0.82~~]1.988 tons per day (tpd) and [~~300~~]475 tons per rolling 12-month period.

Compliance shall be determined daily by multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each fuel combusted at each affected unit by the associated emission factor, and summing the results.

A NO_x CEM shall be used to calculate daily NO_x emissions from the FCCU wet gas scrubber stack. Emissions shall be determined by multiplying the nitrogen dioxide concentration in the flue gas by the mass flow of the flue gas. The NO_x concentration in the flue gas shall be determined by a CEM.

The emission factors for all other emission units are based on the results of the most recent stack test for that unit.

Total daily NO_x emissions shall be calculated by adding the emissions for each emitting unit. Results shall be tabulated every day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions.

iii. Source-wide SO_2

By no later than January 1, 2019, [~~C~~]combined emissions of SO_2 shall not exceed [~~0.82~~]3.1 tons per day (tpd) and 300 tons per rolling 12-month period.

Daily SO_2 emissions from the FCCU wet gas scrubber stack shall be determined by multiplying the SO_2 concentration in the flue gas by the mass flow of the flue gas. The SO_2 concentration in the flue gas shall be determined by a CEM.

Daily SO_2 emissions from other affected units shall be determined by multiplying the quantity of each fuel used daily (24 hour usage) at each affected unit by the appropriate emission factor below.

Emission factors (EF) for the various fuels shall be as follows:

Natural gas: EF = 0.60 lb/MMscf
Propane: EF = 0.60 lb/MMscf
Plant fuel gas: the emission factor shall be calculated from the H_2S measurement or from the SO_2 measurement obtained by direct testing/monitoring.

The emission factor, where appropriate, shall be calculated as follows:

EF (lb SO_2/MMscf gas) = [(24 hr avg. ppmdv H_2S) /10^6] [(64 lb SO_2/lb mole)] [(10^6 scf/MMscf)/(379 scf/lb mole)]

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

Total daily SO_2 emissions shall be calculated by adding the daily results of the above SO_2 emissions equations for natural gas, plant fuel gas, and propane combustion to the wet gas scrubber stack. Results shall be tabulated every day, and records shall be kept which include the CEM readings for H_2S (averaged for each one-hour period), all meter readings (in the appropriate units), and the calculated emissions.

s. 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	Oxgen Ref.	lb/hr
NO_x	3%	3.3

Source: Paper Machines Process Stacks (Each)

Pollutant	lb/hr
PM_{10}	6.65
$PM_{2.5}$	to be determined

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 $PM_{2.5}$. At that time the condensable fraction will be added and a $PM_{2.5}$ limit established in the AO.

C. Subsequent to initial compliance testing, stack testing is required at a minimum of every five years.

t. University of Utah: University of Utah Facilities

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

EMISSION POINT	POLLUTANT	ppmdv (3% O_2 dry)
A. Boilers #3	NO_x	187
B. Boilers #4a & 4b	NO_x	9
C. Boilers #5a & 5b	NO_x	9
D. Turbine	NO_x	9
E. Turbine and WHRU Duct burner	NO_x	15

ii. Stack 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. Boilers #3	NO_x	*	every 3 years
B. Boilers #4a & #4b	NO_x	2018	every 3 years
C. Boilers #5a & #5b	NO_x	2017	every 3 years
D. Turbine	NO_x	2014	every year
E. Turbine and WHRU Duct Burner	NO_x	2014	every year

* Initial test already performed

iii. Testing Status (To be applied to A, B, C, D, and E in i and ii above)

A. After January 1, 2019, Boiler #3 shall only be used as a back-up/peaking boiler. Unit #3 may be operated on a continuous basis with a boiler(s) that is equipped with low NO_x burners.

B. To be applied to boilers #4a, #4b, #5a, and #5b, initial test shall be performed by February 28th of the year specified.

C. To be applied to boilers #4a, #4b, #5a, and #5b , testing will be performed at least every 3 years, between November 1 and February 28/29.

D. To be applied to turbine, and turbine and WHRU Duct Burner, testing will be performed at least every year between November 1 through February 28/29.

u. Vulcraft / Nucor Building Systems

i. R307-350 Miscellaneous Metal Parts and Products Coatings applies to the painting operations at Vulcraft and Nucor Building Systems.

ii. The combined source-wide emissions of VOCs from the joist dip tanks, paint booths, spray painting, degreasers, parts cleaners, and associated operations from the Vulcraft Joist plant and the Nucor Building Systems plant shall not exceed 305.07 tons per rolling 12-month period after January 1, 2014. VOCs emissions shall be calculated from paint and solvent usage based on inventory records.

v. Wasatch Integrated Waste Management District

i. By January 1, 2019, SNCR technology shall be installed and operating on each of the two Municipal Waste Combustors for the reduction of NO_x emissions.

ii. Emissions of NO_x from the Municipal Waste Combustors shall not exceed 350 ppmdv (7% O_2, dry), based on a daily arithmetic average concentration.

iii. Compliance shall be determined by CEMs.

H.13 Source-Specific Emission Limitations in Provo – UT $PM_{2.5}$ 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.

ii. Emissions to the atmosphere from the indicated emission point shall not exceed the following concentrations:

EMISSION POINT	POLLUTANT	ppmdv (3% O_2 dry)
A. Unit #1	NO_x	[~~30~~]36 ppm
B. Unit #4	NO_x	[~~30~~]36 ppm
C. Unit #6	NO_x	[~~30~~]36 ppm

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_x	*	every three years
B. Unit #4	NO_x	January 1, 2017	every three years
C. Unit #6	NO_x	January 1, 2017	every three years

* 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_x burners with Flue Gas Recirculation shall be installed and tested within 18 months of exceeding 300 hours of operation.

b. Geneva Nitrogen Inc.: Geneva Nitrogen Plant

i. Prill Tower:

PM_{10} emissions shall not exceed 0.22 ton/day and 79 ton/yr

ii. Testing

A. Stack testing shall be performed as specified below:

I. Frequency. Emissions shall be tested every three years. The source shall also be tested at any time as required by the Director.

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_x emissions shall not exceed 30.8 lb/hr

iv. Weatherly Plant:

NO_x emissions shall not exceed 18.4 lb/hr

v. Testing

Compliance testing is required on the Prill tower, Montecatini Plant, and Weatherly Plants. The test shall be performed as soon as possible and in no case later than January 1, 2019.

A. Stack testing to show compliance with the NO_x emission limitations shall be performed as specified below:

II. Testing and Frequency. Emissions shall be tested every three years. The source may also be tested at any time as required by the Director.

B. NO_x concentration (ppmdv) shall be used as an indicator to provide a reasonable assurance of compliance with the NO_x emission limitation as specified below:

I. Measurement Approach: NO_x concentration (ppmdv) shall be determined by using a NO_x CEM.

II. Indicator Range: An excursion is defined as a one-hour average NO_x concentration in excess of 200 ppmdv as measured by the NOx CEM. Excursions trigger an inspection, corrective action, and a reporting requirement.

c. PacifiCorp Energy: Lake Side Power Plant

i. Block #1 Turbine/HRSG Stacks:

Emissions of NO_x shall not exceed 2.0 ppmvd (15% O_2) on a 3-hour average basis.

ii. Block #2 Turbine/HRSG Stacks:

Emissions of NO_x shall not exceed 2.0 ppmvd (15% O_2) on a 3-hour average basis.

iii. The owner/operator[~~permittee~~] shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_x and O_2 monitors to determine compliance with the applicable NO_x limitations.

d. Pacific States Cast Iron Pipe Company: Pipe Casting Plant

i. By January 1, 2018, all VOC [~~emissions from all painting operations shall be routed through a thermal oxidizer before being discharged to the atmosphere~~]shall be limited to 141.84 tons per rolling 12-month period.

A. [~~The thermal oxidizer shall at a minimum be 95% efficient in removing VOC emissions, as determined using a method acceptable to the Director.~~]By the twentieth day of each month, a new 12-month total shall be calculated using data from the previous 12 months.

B. [~~After efficiency demonstration, a VOC limit shall be established in the AO by no later than January 1, 2019.~~]Records shall be kept for all periods the plant is in operation.

ii. [~~By January 1, 2017, at a minimum, low NO_x burners with flue gas recirculation technology shall be in operation on the Annealing Oven.~~]The Annealing Oven furnaces are limited to 63.29 MMBtu/hr.

e. Payson City Corporation: Payson City Power

i. Emissions of NO_x shall be no greater than 1.54 ton per day and 268 tons per rolling 12-month period for all engines combined.

ii. Compliance with the emission limitation shall be determined by the following equation:

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

iii. The emission factor shall be derived from the most recent emission test results. The source shall be tested every three years based on the date of the last stack test. Emissions for NOx shall be the sum of emissions from each engine and shall be calculated on a daily basis.

iv. The number of kilowatt hours generated by each engine shall be recorded on a daily basis.

f. Provo City Power: Power Plant

i. Emissions of NO_x shall be no greater than 2.45 tons per day and 254 tons per rolling 12-month period for all engines and boilers combined.

ii. Compliance with the emission limitations shall be determined by the following equations:

Emissions (tons/rolling 12-month period) = (Power production in kW-hrs/day) x (Emission factor in grams/kW-hr) x (1 lb/453.59 g) x (1ton/2000 lbs)

Emissions (tons/rolling 12-month period) = (Power production in kW-hrs/rolling 12-month period) x (Emission factor in grams/kW-hr) x (1 lb/453.59 g) x (1ton/2000 lbs)

The emission factors for NO_x shall be derived from the most recent emission test results.

iii. Each engine and boiler shall be tested every 8,760 hours of operation and/or at least every five years based on the date of the last stack test, whichever occurs sooner.

iv. NO_x emissions shall be the sum of emissions from each engine and boiler. [~~Power productions shall be determined on a rolling 12-month total.~~]The number of kilowatt hours generated by each engine and boiler shall be recorded on a daily basis.

g. Springville City Corporation: Whitehead Power Plant

i. Emissions of NO_x shall be no greater than 1.68 ton per day and 248 tons per rolling 12-month period for all Unit Engines combined.

ii. Internal combustion engine emissions shall be calculated from the operating data recorded by the CEM. Emissions shall be calculated for NO_x for each individual engine in the following manner:

Daily Rate Calculation:

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

D = (X * K)/453.6

The daily outputs are summed into a monthly output.
The monthly outputs are summed into an annual rolling 12-month total of pollutant in tons/year.

SIP Subsection IX.H.11, 12, and 13, Control Measures for Area and Point Sources, Emission Limits and Operating Practices, PM2.5 Requirements

Summaries and Responses to Comments Received During the November 1 to December 2, 2013, Public Comment Period

Note that when EPA submitted their comments on the Part H SIP, they also included comments on SIP IX.A.21 and 22. Summaries and responses to these comments are included in this document.

TABLE OF CONTENTS

General Comments

G-1 [Comment submitted by Bucky Cash]: I don't believe there is a one-size-fits-all solution to this, and therefore don't believe the State of Utah should hold itself to the same federal air quality standards as other states. Please implement standards that will improve our air quality beyond federal standards.

Response to G-1: DAQ appreciates your concern, but has neither the expertise nor the mandate to establish state health standards that are more stringent than those established by the EPA. Be assured that those standards are established to protect the most sensitive among us, and with an adequate margin of safety.

G-2 [Comment submitted by HollyFrontier]: The benefit of additional controls on oil refineries has not been quantified. Given the minor portion of the inventory attributable to refining and the minor reductions that are achievable through even the strictest controls, these proposed controls will not contribute to achieving the NAAQS. The benefit of these additional controls has not been quantified. Furthermore, the cost per ton for such controls is significantly higher than what has been considered in the past for RACT.

Response to G-2: The Clean Air Act (CAA) requires that the State Implementation Plan (SIP) "provide for the implementation of all reasonably available control measures as expeditiously as practicable (including such reductions in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology) and shall provide for attainment of the national ambient air quality standards." The regional scale modeling used to support the SIP is not suited to the evaluation of a single, localized control strategy. The aggregation, however, of reasonably available measures is shown through the model to be sufficient to provide for attainment of the National Ambient Air Quality Standards (NAAQS).

Going Forward in light of Subpart4

[All the comments in this section were submitted by EPA Region 8]

SP4-1: The January 4, 2013 court ruling held that the EPA should have implemented the 2006 PM2.5 NAAQS based on both Clean Air Act (CAA) subpart 1 and subpart 4. Thus, the state should submit a subpart 1 and subpart 4 moderate-area SIP. Our review of the draft SIPs indicates that they do not address subpart 4. Therefore, these aspects of the SIP are not approvable (to be discussed further in these comments).

Response to SP4-1: DAQ is aware that there are elements in the draft SIPs that are suitable to subpart 1 only, and do not address the specific requirements of subpart 4. These plans were substantially complete when the courts remanded the rule DAQ was following to develop them. However, these SIPs represent a significant step forward in terms of achieving compliance with the 2006 NAAQS. Additionally, these plans may also help Utah meet the subpart 4 requirements, although EPA has failed to promulgate those requirements. It is our stated intention to submit these SIPs to the EPA, and to then supplement them to address the Subpart IV requirements by the date proposed in EPA's rule (December 31, 2014).

SP4-2: In the draft SIPs, the state references the "EPA Clean Air Particulate Implementation Rule (FR 72, 20586)." However, this rule has been remanded, and the March 2 2012 guidance titled "Implementation Guidance for the 2006 24-Hour Fine Particulate (PM2.5) National Ambient Air Quality Standards (NAAQS)" has been withdrawn. These two documents no longer adequately define what the SIPs should contain. Additionally, 40 CFR 51.1000, Subpart Z – Provisions for Implementation of PM2.5 National Ambient Air Quality Standards should not be used because the information in the CFR comes from the 2007 Clean Air Particulate Implementation Rule that was remanded.

Response to SP4-2: DAQ understands this to be the case, and will eliminate such references as it revises these SIPs to specifically address the subpart 4 moderate-area requirements by the proposed date upon which such plan revisions are due. DAQ notes that the implementation guidance states will be expected to use in support of these efforts to address subpart 4 has not yet even been proposed.

SP4-3: In the draft SIPs, the state requests a five-year extension to the attainment date from December 14, 2014 and demonstrates attainment by December 14, 2019. This was possible under subpart 1, but due to the January 4 2013 court decision, is no longer possible because subpart 4 now applies. Under subpart 4, the moderate area attainment date is December 31, 2015. If the area does not attain by this date, it will be reclassified as serious and given a new attainment date of December 31, 2019. Thus, the state does not need to request a 5-year extension, but should start working on its serious area SIP.

However, the state is still required to submit a moderate area SIP that satisfies the applicable CAA requirements, including the requirements to adopt and implement [by December 14, 2013] reasonably available control measures (RACM / RACT). We reiterate that in order to support a demonstration that attainment by December 31, 2015 is impracticable, the state must show that it has adopted "all available control measures that are technologically and economically feasible. For the serious area SIP, all sources will need to be reviewed for best available control measures (BACM / BACT), which will have a later implementation date.

Response to SP4-3: DAQ understands that the specifics to be addressed by the underlying demonstration of attainment are now different. This is one of the revisions that can be made between now and December 31, 2014. Nevertheless, the attainment demonstration undertaken and relied upon by the draft SIPs provides a quantitative assessment of these airsheds in the years encompassing specific requirements of subpart 4, for both moderate and serious areas. Based on this analysis, one can readily surmise that attainment by the moderate-area attainment date (December 31, 2015) will not be practicable.

The implementation date for all reasonably available control measure / reasonable available control technology (RACM / RACT) prescribed by the moderate area planning requirements was December 14, 2013. Regardless of whether the implementation requirements for RACM / RACT in these proposed SIPs is shown to be as expeditious as practicable, it is simply not reasonable to expect that implementation of these (new) measures could be achieved by a date that has now passed.

As DAQ looks forward to the serious-area planning requirements, with an expectation of best available control measures / best achievable control technology (BACM / BACT), some of the determinations made with regard to control measures in these draft SIPs will have to be re-evaluated, in terms of their extent and their implementation dates.

Re-classification of these areas from moderate to serious can be either mandatory (as of the moderate-area attainment date) or discretionary (sooner than that). DAQ's understanding is that, if the EPA is to use its discretion in making such re-classification, the agency can use whatever information is available to draw such conclusion. It would seem that the scope of this information is not limited to just the demonstration included in a forthcoming moderate-area plan revision.

SP4-4: In the draft SIPs, the state discusses RACM / RACT with implementation dates that range from 2014 to 2019. Under subpart 4 (CAA section 189(a)(1)(C)), RACM / RACT for a moderate area SIP shall be implemented no later than four years after designation [by December 14, 2013], and under Subpart 1 (CAA section 172(c)(1)), as expeditiously as practicable. In the draft SIPs, some of the control measures won't be implemented until the end of 2019, the serious area attainment date. This would not seem to meet the requirements of subpart 4.

There is no analysis showing that it would be infeasible to implement the control measures earlier. We also note that to support a demonstration that attainment by the moderate area attainment date (December 31, 2015 under subpart 4) is impracticable, the state must show that it has adopted "all available control measures that are technologically and economically feasible."

Response to SP4-4: DAQ is aware that it must now address the planning requirements of subpart 4 in addition to the more general requirements of subpart 1. We would direct the reader to the discussions provided in response to comments no SP4-3 and H-3.

SP4-5: The draft SIPs do not acknowledge that milestones (under subpart 4) must be submitted every three years until the areas are re-designated to attainment.

Response to SP4-5: DAQ understands that the specifics to be addressed in the SIP narratives are now different. The attainment demonstration underlying both SIPs was structured to include the milestones that were required if subpart 4 did not apply. This is discussed in each of the SIP narratives. Under subpart 4, the milestone requirements are to be evaluated every three years until the areas are re-designated to attainment. DAQ will make the appropriate revisions as it address the subpart 4 moderate-area requirements by the proposed date upon which such plan revisions are due.

SP4-6: Regarding milestones under subpart 4, the General Preamble discusses that CAA section 189(c) does not articulate the starting point for counting the 3-year period for quantitative milestones. It states that EPA believes it is reasonable to begin counting from the due date for the applicable plan revisions containing the control measures for the area. EPA's proposed rule (if finalized) establishes this date as December 31, 2014.

Response to SP4-6: DAQ agrees. See discussion in response to comment number SP4-5.

SP4-7: In the draft SIPs, the state indicates that VOC and ammonia are precursors that are presumed to be excluded unless it is demonstrated that they are a significant contributor to PM2.5 concentrations. This presumption no longer applies under subpart 4. Instead, all control requirements applicable to major stationary sources of PM2.5 also apply to major stationary sources of PM2.5 precursors, "except where the Administrator determines that such sources do not contribute significantly to PM2.5 levels "which exceed the standard in the area". The General Preamble (57 FR 13498; 13541) states that "EPA intends to make a formal determination as to whether major stationary sources of PM10 precursors contribute significantly to PM10 levels in a particular area when it takes rulemaking action on the individual moderate area SIPs." We intend to apply the same approach for PM2.5. In order to adequately make this determination, documentation will be needed showing that ammonia controls for stationary sources would have no effect on predicted PM2.5 concentrations. This might be done by showing 1) that the fraction of ammonia emissions in the inventory from stationary sources is small relative to total anthropogenic emissions, and 2) that stationary source ammonia emissions are a negligible fraction of total ammonia in the domain.

Response to SP4-7: DAQ agrees, and will work with EPA to provide the necessary information as these SIPs are revised to specifically address the subpart 4 moderate-area requirements.

SIP Deficiencies

[All comments in this section were submitted by EPA Region 8]

SD-1: We are seeking an explanation as to why the state chose to use the projected actual emissions, of point sources, in its attainment modeling. The General Preamble (57 FR 13497, April 16, 1992) contemplates that source allowable emission limits may need to be reduced to the levels sources are actually emitting to support the modeled attainment demonstration. In addition Region 8 had communicated to the UDAQ that the SIP submittal needs to provide evidence that projected actual emissions will not be exceeded by an amount that would interfere with attainment or maintenance of the PM2.5 NAAQS. In our review of the point source reduction summary table provided by the state, it appears that the proposed allowable emissions are substantially greater than the modeled emissions. In any case, the draft SIP appears to lack the necessary evidence that projected actuals will not be exceeded by an amount that would interfere with attainment or maintenance.

Response to SD-1: DAQ would first point out that it is providing EPA with the information they could not access from the RACT Summary Table regarding the emissions at each of the identified sources. We believe that the discrepancies between the emissions that were modeled as projections of actual emissions vs. the allowable emissions will be found to be a) not as great as imagined, and b) limited to a small number of sources.

Having said that, DAQ would like to explain its use of projected actual emissions in the modeled attainment analysis.

Firstly, DAQ's approach is in accordance with EPAs guidance.

From a technical standpoint, DAQ relied upon "Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze" (EPA – 454/B-07-002, April 2007).

DAQ believes the guidance makes this particular recommendation because of the chemical reactivity of both PM2.5 and ozone. In both cases, the chemistry is non-linear, and model predictions regarding concentrations of these pollutants are functions of the chemical equilibrium present at any given time in the airshed. Overly conservative projections of emissions can misrepresent this equilibrium and lead to erroneous model results. DAQ was mindful of making reasonable projections in the future-year emissions, and did not use an overly conservative representation of permissible emissions from stationary sources. The modeling analysis also accounts for permitting actions that transpired between the 2010 baseline and now. This accounting is consistent with the notion of a reasonable projection.

More specifically, EPA addresses how emissions should be estimated for future years (see Section 17.6), and notes: "The goal of making projections is to obtain a reasonable estimate of future-year emissions that account for the key variables that will affect future emissions." Concerning growth as one of those variables: "A representative growth rate should be identified from the available data sources and all information known about the sources and sectors. Stakeholder review of the data can be helpful during this step; for example, an industrial facility with large projected emissions may be able to review the data and provide additional information for a more informed future-year estimate."

The alternate approach would have been to model each of the identified point sources at its maximum allowable emission rate. This however leads to the projection of a worst-case scenario. It would assume that every one of these sources was emitting at its maximum allowable rate, all at the same time. Furthermore, this bias is made more extreme when one considers an averaging time that is less than an annual average. 24-hour emission rates (consistent with a 24-hr. PM2.5 standard) naturally show more fluctuation than an annual rate; a fact that is accounted for in the establishment of emission limits.

A worst-case scenario may be satisfying from a legal standpoint, but would not represent a reasonable estimate of future emissions. Instead, it is more reasonable to look at the collection of these sources in aggregate. It is much more realistic to assume that while one or more sources are operating at rates higher than average, other sources are operating at lower rates. This is the law of averages.

DAQ has, in the past, relied on allowable emissions for SIP attainment demonstrations. Of particular note would be the 1991 SIP for PM10. We note however, that this was done within the scope of an inventory based approach, used in conjunction with a receptor model that was not able to replicate the complex non-linear chemistry at work in these airsheds. Underlying that SIP was a 1 to 1 conversion rate from precursor to particle. Clearly this is not the case.

These draft SIPs are based on photochemical modeling that includes the ability to reconcile non-linear chemistry, and makes evaluations concerning PM2.5 concentrations, in a relative sense. EPA's Modeling Guidance discusses the modeling of future concentrations in a relative sense and concludes: "Because the test is relative, in most cases, actual emissions should be used. The actual emissions should be representative of emissions on high PM2.5 days (days that exceed the NAAQS). Since the absolute predicted concentrations are not used directly, allowable emissions may overestimate the changes in concentrations due to the identified sources." This is contrasted with modeling in other (non-SIP) applications: "Modeling with allowable emissions is sometimes warranted. For example, for permit modeling, we generally compare the absolute predicted modeled concentrations against the NAAQS or the PSD increment. Therefore, in the case of permit modeling, it is sometimes appropriate to model with allowable emissions."

Furthermore, in addressing the creation of future-year inventories and air quality model inputs, EPA notes: "Every attempt should be made to use consistent approaches between the future year and the base year for all of these modeling steps. Inconsistencies in approaches between the future-year modeling and the base-year modeling can lead to artificial differences in air quality modeling results that can affect conclusions. Therefore, it is critical to avoid such differences whenever possible." DAQ notes that the base-year inventories were constructed using actual emissions from 2008 (projected forward to the year 2010. Also, sources not present in the 2008 inventory were added into the projection-year inventories at 90% of their allowable emissions).

In its comment, EPA points us to the 1992 General Preamble which says: "When developing a control strategy and demonstrating attainment with *dispersion modeling*, the State *may* determine that some actual emissions must be reduced and also some allowable emissions must be reduced to the levels that the sources are actually emitting". (57 FR, 13498, April 16, 1992) This language does not definitively indicate that states are required to base their attainment demonstrations on allowable emissions, rather, the language EPA provides is suggestive and somewhat discretionary. DAQ would note that air quality modeling has advanced a long way since 1992, and that the Modeling Guidance prepared in 2007 represents a more technically sound basis for assessing future-year emissions in a photochemical model.

Finally, DAQ would point out that Utah is not the only state to have based its SIP on projected allowable emissions. EPA approved SIPs for the San Joaquin Valley and the South Coast regions that estimated point source emissions using projected growth rather than allowable emissions. In taking action, EPA noted that: "These methodologies for projecting future emissions based on growth factors and existing Federal, State, and local controls were consistent with EPA guidance on developing projected baseline inventories… [W]e conclude that the projected baseline inventories for 2009, 2012, and 2014 were prepared consistent with EPA's guidance on development of emissions inventories and attainment demonstrations and, therefore, provide an adequate basis for the RACM, RFP, and attainment demonstrations in the Plan." (at 76 FR 69907-08)

SD-2: The contingency provisions in the draft SIPs do not satisfy applicable requirements. First, as noted in the General Preamble (at 57 FR 13543), the rule containing the contingency measure must clearly state that the measure will go into effect upon a determination by the EPA that the area has failed to make RFP or attain the NAAQS by the statutory date. This has not been made clear in either the rule or the SIP. Second, the General Preamble notes that the contingency measures "should be approximately equal to the emissions reductions necessary to demonstrate RFP for one year." The state has not estimated the emission reductions that would be achieved or whether those reductions would equate to one years' RFP.

Response to SD-2: As it works to revise these SIPs to specifically address the subpart 4 requirements, DAQ will clarify in the SIP narratives the conditions under which the contingency measures would become necessary. With regard to the guidance provided in the General Preamble, DAQ notes the recommendation provided by the EPA, but would point out that it is not a specific criterion for SIP approvability.

SD-3: Either the state must include any banked emission reduction credits (ERCs) in the attainment modeling, or the applicable rules must include definitive language stating that no pre-baseline ERCs may be used within the PM2.5 nonattainment areas to offset increases of PM2.5, NOx, SO2, or VOC from major stationary source construction or modification. If the ERCs are added to the modeled emissions, they should be identified by species, location, and vertical layer.

Additionally, the state is not adopting a minor source offset rule as part of the SIP. While we have indicated that our regulations contain no specific requirement for minor source offsets, we have also indicated that the SIP or SIP rules must specify an enforceable approach by which Utah will determine whether minor source construction or modifications will prohibit such if it would interfere with attainment or maintenance of the NAAQS or control strategy. It does not appear that the existing minor source NSR rules require any type of impact analysis or tracking in nonattainment areas.

Response to SD-3: To the first point, DAQ agrees, and will commit to revising its permitting rules to provide such definitive language as it addresses the requirements specific to subpart 4 by the applicable due-date.

Concerning minor sources, growth has already been accounted for by the economic forecasts applied to the emissions from that sector. The inventories generated thereby include milestones in 2014 and 2017 as well as the projected attainment year of 2019. The moderate-area planning requirements of subpart 4 will only require an assessment for an attainment year of 2015; one year from the date upon which the plan will be due. Any such tracking mechanism, as envisioned by Region 8, would be unnecessary.

SD-4: Under Chapter 8 of the draft SIPs, we have concerns regarding the "full Implementation Reduction" and "Benchmark Emission Reduction" equations. These equations were changed from the 2012 draft SIPs. Why were these equations changed, and how would the changes affect Reasonable Further Progress (RFP)?

Response to SD-4: DAQ notes that, with respect to the 2012 proposal, the text of the 2013 proposal was corrected as follows:

- The quantities expressed in the calculation of the "Full Implementation Reduction" were reversed so as to change the overall sign of the result,
- the "milestone Date Fraction" was modified to account for the change in baseline years (from 2008 in the 2012 proposal to 2010 in the 2013 proposal), and
- the operator in the "Benchmark Emission Reduction" equation was changed to express multiplication rather than subtraction.

Each of these quantities now correctly matches the definitions provided in 40 CFR 51.51.1009(f) (from Subpart Z). Nevertheless, the mathematics behind the RFP values reported in Tables 8.1 was performed correctly in both the 2012 and now this 2013 version of the proposed SIP. These are the values appearing under the column headings "rfp".

Having said that, we would point out that the demonstrations made by Tables 8.1 were necessary when the underlying planning requirements considered only subpart 1. Now that we must also consider the subpart 4 planning requirements, anything reported in Tables 8.1 is moot. In fact, the very definitions these equations were to represent come from Subpart Z, which as EPA has pointed out, was remanded and no longer applies.

Part H

General

H-1 [submitted by EPA Region 8]: Requirements for existing controls are not included as part of RACT for some sources. Instead, only requirements to install new controls appear in draft SIP subsections IX.H.12 and 13 (individual instances are cited in source-specific comments). The state needs to identify the existing local measures in the area that contribute to attainment of the NAAQS in the area, so the EPA can approve the measures specifically as RACT.

Response to H-1: DAQ notes that the CAA requires (at 172(c)(1)) that the plan provisions "provide for the implementation of all reasonably available control measures as expeditiously as practicable (including such reductions in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology) and shall provide for attainment of the national ambient air quality standards." Plan provisions shall also "include enforceable emission limitations, and such other control measures, means or techniques… schedules and timetables for compliance as may be necessary or appropriate to provide for attainment… by the applicable attainment date" (at 172(c)(6)). Furthermore, it states that the "plan provisions shall require permits for the construction and operation of new or modified major stationary sources anywhere in the nonattainment area" (at 172(c)(5)).

EPA is somewhat more explicit in 40 CFR 51 Subpart G – Control Strategy. Section 51.112 requires that "each plan must demonstrate that the measures, rules and regulations contained in it are adequate to provide for the timely attainment and maintenance of the NAAQS it implements."

DAQ recognizes the importance of identifying and ensuring the implementation of RACM / RACT and also the importance including enforceable emission limitations in the plan. We also recognize the overlap between the two requirements, but would point out that, indeed, they are separate requirements.

Each of these nonattainment areas is a complex urbanized area, and includes sources ranging from small to large-enough so as to have been identified in these PM2.5 SIPs as warranting specific attention for purposes of ensuring RACM / RACT. Many of these larger sources include a litany of source components that also range from small to large. Many of these smaller source components are no different from those owned and operated by smaller sources. While it remains important to ensure that the operation of these components is in keeping with RACM / RACT, attainment or nonattainment of the NAAQS does not hinge on the emissions from such sources.

By contrast, there are other more significant source components that do, by themselves, have the potential to directly influence air quality. For source components such as these, it "may be necessary or appropriate" to include in the SIP an enforceable emission limitation or control measure. In essence, it is not necessary or appropriate to include, in the SIP, an enforceable emission limitation for every last little piece of equipment simply because it passed a RACT evaluation. Furthermore, some discretion is necessary in determining how to distinguish these from the source contributions that do belong in the SIP.

Given this important distinction, DAQ would point to its federally approved NSR permitting program and its role as a required element (from 172(c)(5)) of these plan provisions. The approval orders issued as a consequence of this program offer a repository for the many emission limitations that would not rise to the level of importance compelled by the SIP. The DAQ also has a minor source permitting program, and a BACT analysis is required for minor sources and for major sources that are below significance. Collectively, these limits and the NSR rules and regulations that prescribe them, are part of a control strategy that is adequate for timely attainment of the PM2.5 NAAQS.

Hence, SIP Sections IX. Part H.11, 12, and 13 do not contain emission limitations for every individual control element described in the RACT Evaluation Reports.

First, if in the judgment of DAQ an existing control did not rise to the level that warrants specific inclusion in the SIP, such existing limitation was left to the NSR program.

Second, there are other federally approved SIPs programs such as new source performance standards (NSPS) or national emission standards for hazardous air pollutants (NESHAP) that specifically include enforceable emission limitations for some of these sources. In cases where RACM / RACT was determined to be represented by one of these limitations, DAQ saw no need to include it again here. Thus, if as part of the RACM / RACT analysis, a new control technology was identified and required as part of this SIP, a new limit has been added in SIP Sections IX. Part H.11, 12, or 13.

So, having identified the existing local measures in the area that contribute to attainment of the NAAQS in the area, DAQ is supportive of EPA in its effort to approve these measures specifically as RACT for the area. However, should EPA expect that each of these measures belongs in SIP Sections IX. Part H.11, 12, or 13, we would strongly disagree.

H-2 [submitted by EPA Region 8]: In some instances within the RACT evaluation report, certain emission control options have been identified as RACT, but the draft SIP subsections IX.H.12 and 13 propose no corresponding RACT requirement.

Response to H-2: The limits in Part IX.H are based on the emissions limits that result from the implementation of RACT. The DAQ, wherever possible, did not require a specific control technology in IX.H, in order to allow the sources options to achieve the identified limit. The DAQ believes this flexibility may result in even lower emissions as new control technology is developed. A prescriptive SIP would not allow this flexibility for improvement.

H-3 [submitted by EPA Region 8]: In nearly all instances where new controls and/or emission reductions are required, sources are being given until 2017 or 2019 to comply. Little or no explanation could be found for why that amount of time is necessary (individual instances are cited in the source-specific comments).

Response to H-3: The DAQ required point sources to identify implementation timeframes. The DAQ recognizes that most of the pollution control technologies being required of industry are not “off the shelf”, and a significant lead time is required to design, purchase, install, test and implement these technologies. DAQ agrees however, that more documentation is necessary to establish that these implementation dates are “as expeditious as practicable”. As we now consider the additional planning requirements of subpart 4, there are a number of areas in which these draft SIPs will have to be supplemented or revised.

DAQ must address these subpart 4 issues in two steps. First, it will be necessary to submit a moderate-area SIP that (as now proposed) includes an attainment date of December 31, 2015. The associated date for RACM / RACT implementation is December 14, 2013. Regardless of whether the implementation requirements for RACM / RACT in these proposed SIPs is shown to be as expeditious as practicable, it is simply not reasonable to expect that implementation of these (new) measures could be achieved by a date that has now passed.

Second, it will likely be necessary to submit a serious-area SIP that appears to include an attainment date of December 31, 2019. As DAQ looks forward to the serious-area planning requirements, with an expectation of BACM / BACT, some of the determinations made with regard to control measures in these draft SIPs will have to be re-evaluated, in terms of their extent and their implementation dates.

Any revisions made to the RACT Evaluation Report will certainly need to consider both of these submittals. DAQ will refine the implementation schedules at that time, and provide sufficient documentation to support any conclusions therein.

Please be aware that as part of the SIP modeling effort, various iterations utilized the most conservative controls identified in each RACT analysis to determine if the most stringent point source controls would result in advancing the attainment date. The results of this modeling run lead to the conclusion that strict and early implementation of RACT would not advance the attainment date, as point sources make up a small percentage (<12%) of the emissions contributed to the airshed.

The following comments are the Region's general review of the SIP narratives and also comments based on Clean Air Act part D- Plan Requirements for Nonattainment Areas, subpart 1 – Nonattainment Areas in General, subpart 4 - Additional Provisions for Particulate Matter Nonattainment Areas, and State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990 (57 FR 13498; April 16, 1992).

H-4 [submitted by EPA Region 8]: The RACT Summary Table, found on the state 's website, lists emission reductions in tons per year (tpy) which are credited to various stationary sources. This is beyond the reductions achieved by existing emission controls. For some sources, the proposed RACT requirements do not include any requirement to achieve those additional emission reductions. For the additional reductions to be creditable, a requirement to achieve such reductions needs to be reflected in the SIP. Further detail can be found in Attachment 2.

Response to H-4: The RACT summary table is not an official SIP document but was developed to show the public the sources that underwent a RACT analysis and the reduction in criteria pollutants that would be realized due to implementation of the identified controls. The table did accurately reflect the reductions that would be achieved, but is now outdated due to changes in RACT as a result of comments received during the public comment period.

The limits in Part IX.H are based on the emissions limits that result from the implementation of RACT. The DAQ, wherever possible, did not require a specific control technology in IX.H, in order to allow the sources options to achieve the identified limit.

H-5 [Submitted by EPA Region 8]: IX.H.11.d - This subsection says "All emission limitations listed in Subsections IX.H.12 and IX.H.13 apply during steady-state operation, unless otherwise specified in the source-specific conditions listed in IX.H.12 and 13." This is inconsistent with CAA requirements that SIP emission limits apply at all times, including periods of startup, shutdown, and malfunction (SSM). See CAA section 302(k); 76 FR 21641 (April18, 2011). EPA's interpretation on this point has been upheld in several cases, including one involving our SIP call concerning Utah's unavoidable breakdown rule. See *US Magnesium, LLC* v. *EPA*, 690 F.3d 1157, 1170 (lOth Cir. 2012).

Response to H-5: The UDAQ recognizes the importance of SSM emissions to EPA. Rather than resolve issues involving SSM emission at this time, the UDAQ recommends these issues be resolved in the next round of SIP development.

In the meantime, the UDAQ makes the point that in all cases where a plantwide daily limit exists, this limit accounts for and includes startup/shutdown emissions.

H-6 [Submitted by EPA Region 8]: IX.H.11.e.i.C and D - These subsections each include the following statement: "The back half condensables shall also be tested using the method specified by the Director." Everywhere else in these subsections; the language reads, "EPA-approved testing methods acceptable to the Director." The same language should be used here.

Response to H-6 The DAQ agrees with the comment. The language has been changed to require the use of “EPA-approved testing methods acceptable to the Director.”

H-7 [Submitted by EPA Region 8]: IX.H.11.e.i.G - This subsection does not list a specific method for VOC testing. Are there no methods that can be specified up front for VOCs? Please explain.

Response to H-7: The test requirements for volatile organic compound (VOC) emissions are highly dependent on source and emission unit specifics. Testing for VOC emissions at paint booths is substantially different than measuring fugitive VOC emissions from equipment leaks or direct VOC emissions from a combustion stack. As each of these tests is highly unique, rather than attempting to list every possible allowable test method (previously approved by EPA, and acceptable to the Director), the most routine testing method for VOCs has been incorporated into the SIP.

IX.H.11.e.i.G VOC: 40 CFR 60 Appendix A, Method 25A or EPA-approved testing methods acceptable to the Director.

H-8 [Submitted by EPA Region 8]: Condensable particulate matter: There are a few instances where the RACT Evaluation Reports and proposed RACT emission limits in draft SIP subsections IX.H.12 and 13 do not take into account condensable PM. Individual instances are cited in the source-specific comments below. We are seeking an explanation why this was not done. If there is a valid basis for not considering condensable PM in particular cases (for example, if the source does not emit condensable PM or emits a de minimus amount), the TSD or the SIP should explain that basis.

Response to H-8: As EPA has commented previously, the "EPA Clean Air Particulate Implementation Rule (FR 72, 20586)" has been remanded, and the March 2, 2012, guidance titled "Implementation Guidance for the 2006 24-Hour Fine Particulate (PM2.5) National Ambient Air Quality Standards (NAAQS)" has been withdrawn. Additionally, 40 CFR 51.1000, Subpart Z- Provisions for Implementation of PM2.5 National Ambient Air Quality Standards should not be used because the information in the Code of Federal Regulations (CFR) comes from the 2007 Clean Air Particulate Implementation Rule that was remanded. Note that 51.1002 (c) (from subpart Z) says “States must establish such limits taking into consideration the condensable fraction of direct PM2.5 emissions.” Based on these statements, UDAQ does not agree that setting a limit on the condensable fraction of PM2.5 emissions without adequate testing data, especially as it pertains to setting the condensable/filterable ratio on new and previously unseen equipment and processes. This is the case whenever a condensable particulate limit has been ‘deferred’ or language is present which requires the source to conduct testing to establish the ratio between condensable and filterable PM2.5.

H-9 [Submitted by EPA Region 8]: Emission limits averaging times. 'Some of the proposed source-specific RACT emission limits have averaging times longer than 24 hours. Individual instances are cited in the source specific comments below. We are seeking an explanation how averaging times longer than 24 hours can represent RACT in a plan that is intended to attain a 24-hour NAAQS.

Response to H-9: All RACT limits were initially determined based on protection of the 24-hour standard. Although DAQ will respond to each specific instance with its response to the individual source comments, a general explanation is that each limit must be viewed for its intended purpose. Some limits, which can be viewed as “indirect limits” are included as general RACT requirements to improve overall emission performance. An example of these would be the general refinery requirements in SIP Section IX.H.11.g, which are intended to bring all refineries up to current NSPS Subpart Ja and GGGa emission standards. Other “direct” SIP limits are direct controls on emissions. The difference between the two types is that indirect limits are not included in the attainment demonstration model, while direct limits are. To use our previous example, the SO2 emissions from the refineries are modeled using the SIP Cap allowables, and not by including the specific limitations on SO2 and H2S that are found in IX.H.11.g. Hence, the limits found in that section, which are indicators of general RACT performance, do not need a strict 24-hour averaging period. Instead, the averaging periods found in the associated NSPS (either Subpart Ja or GGGa) are both adequate and appropriate.

H-10 [Submitted by EPA Region 8]: Stack test frequency. There are a number of instances where stack testing is required only once every 3 to 5 years. Examples are: Central Valley Water Reclamation, Chemical Lime, Great Salt Lake Minerals, Kennecott Power Plant, Kennecott Refinery, Nucor Steel, Proctor & Gamble, University of Utah, BYU, Geneva Nitrogen, and Provo City Power. We are concerned with stack test frequencies longer than one year. Please explain why these test frequencies are sufficient to ensure continuous compliance with the limits.

Response to H-10: Stack testing frequency is based on engineering judgment and the permit writer's knowledge regarding the specific sources process and history. How close a source is to a threshold (significance, PSD, etc.), what existing stack requirements are in place, and whether the equipment is controlled with industry wide accepted technology are some things considered when setting testing frequency. If the analysis by the engineer revealed a need for annual sampling it would have been required.

H-11 [Submitted by EPA Region 8]: Excess emission reporting. There are no proposed requirements for any sources to report excess emissions. Please explain how this will be addressed.

Response to H-11: The reporting of excess emissions remains a requirement of UDAQ's existing breakdown rule and emissions inventory reporting requirements. These can be found at R307-107 and R307-150 respectively. Every approval order requires the permittee to comply with the requirements for breakdown reporting. No additional SIP reporting requirements are necessary.

H-12 [This comment was submitted by 1,426 people]: The industrial sector will be allowed to expand its pollution by more than 12 percent! The commenter requested that the UDAQ make the SIP more protective by requiring measures such as the following:

* Limit pollution from all of the refineries by requiring controls such as Pall blowback filters, fabric filter baghouses, wet scrubbers, SOX transfer catalysts, CO boilers, SCR and a rigorous program to accurately measure and reduce fugitive VOC emissions from the refineries.
* Reduce pollution from all of Kennecott's boilers and CHP units, at the smelter, refineries and MAP plant, by requiring installation of selective catalytic reduction (SCR) technologies. Order Kennecott to retire the Unit 4 boiler at the Utah Power Plant more quickly, by 2016 rather than 2018.
* Curb emissions from Nucor's mini steel mill by requiring that it purchase vehicles with the lowest possible emissions when it replaces its mobile diesel-powered equipment, and by installing SCR on its two billet reheat.

Response to H-12: Major sources of air contaminants (industrial sector) will be required to comply with the major NSR permitting rules R307-403) for sources located in a nonattainment area. One component of these permitting rules is the requirement that the source obtain emission credit reductions, or offsets, if it is a new major source or a major source seeking a significant increase in emissions that could impact the nonattainment area. A second component of these permitting rules is the requirement that the source apply lowest achievable control technology (LAER).

General Refinery

H-13 [Submitted by EPA Region 8]: IX.H.11.g: There are no requirements in this subsection for CEMS. The draft SIP subsections for the individual refineries in IX.H.12 rely on CEMS for determining some of the emissions and emission factors for sulfur dioxide (SO_2), NO_x and H_2S. CEMS are required for other sources as well. Requirements to operate and maintain CEMS should be included in IX.H.11.g, or in IX.H.12., or both.

Response to H-13: We disagree with this comment. The requirements for operating and maintaining continuous emissions monitoring systems (CEMs) are found in IX.H.11.f. as they apply to all sources and source categories. Section IX.H.11.g is a section which applies only to refineries, and placing the CEMs requirements here would limit their effectiveness for other source types.

H-14 [Submitted by EPA Region 8]: IX.H.11.g.i.A.I: We have several comments on this subsection:
1) This subsection specifies SO_2 emission limits of 25 ppmdv and 50 ppmdv at FCCUs. Please explain how it was determined that 25 ppmdv and 50 ppmdv represent RACT. We are not aware of any RACT Evaluation Report in the TSD that explains this.

2) This subsection specifies a 365-day rolling average basis and a 7-day rolling average basis for the emission limits. Please explain how averaging times longer than 24 hours can represent RACT in a plan that is intended to attain a 24-hour NAAQS.

3) What value was modeled in the attainment demonstration for SO_2 emissions on a 24-hour basis from FCCUs? Was it greater than 50 ppmdv, to account for greater variability than a 7-day average?

4) This subsection requires compliance "By no later than January 1, 2018." Please explain why an earlier date would not be achievable.

Response to H-14:

1) As found in the "UTAH $PM_{2.5}$ SIP RACT SUPPORT Revised RACT Evaluation Report and Accompanying RACT Evaluation Workbook for Four Refineries, Task 3, Revision 1, Work Order No. 07" Submitted to UDAQ by TechLaw, Inc. on July 11, 2013, there is a Section 4.0 Emission Reductions Achievable for each of the four refineries. As an example, the following language can be found in the first paragraph of that section for Tesoro:

   At a minimum, compliance with the subpart Ja SO_2 emission limits should be considered.

   These limits are what result in the values found within the table on page 9 of that report. Also, see page 12 which provides TechLaw's recommendations on methodology. Similar values can be found for the other refineries – either to achieve or (for the single refinery already attaining those values) maintain those limits. See pages 16, 33, 34, 38, and 41 as well as Tables A-7 and A-8 for further details.

2) The long-term 365-day rolling average basis limit of 25 ppmdv is an expression of overall performance and maintenance of the FCCU. While it is not a direct limiter on emissions on a short-term basis, it is a good indicator of emission trends. On the other hand, the much shorter-term 50

ppmdv on a 7-day rolling average basis does limit emissions – even within the context of a 24-hour NAAQS. The formation of fine particulate through secondary chemical processes is not a rapid process. There is some degree of persistence to emissions – both within the domain of chemical interaction in the atmosphere as well as in the realm of the model used to predict the attainment demonstration. This persistence is accounted for specifically through the short-term rolling average compliance demonstration. A temporary high spike in SO_2 emissions can be adjusted for by more aggressive SO_2 removal on subsequent days, without affecting attainment of the NAAQS.

3) The value modeled was variable based on a projection of actual emissions by monthly profile. The community multi-scaled air quality (CMAQ) model used data prepared by the pre-processor SMOKE, which took the annual SO_2 emission rate as an input, along with information about operating schedule, stack information (height, temperature, flow rate, etc.), and other general source information and calculates an hourly emission profile representative of performance at that given hour (see general modeling comment). In some cases that value could be as high as 50 ppmdv; in other cases, the value might be somewhat lower.

4) At least two of the four refineries listed in Section IX.H.12 are installing wet gas scrubbers to meet the SO_2 emission limits listed in Section IX.H.11.g.i.A.I. These items represent large capital investments with significant lead times, engineering, construction, startup, shakedown and testing involved. This date was reached through negotiation with the sources, and allowed for a full year of operation prior to the January 1, 2019, attainment date.

H-15 [Submitted by EPA Region 8]: IX.H.11.g.i.A.III: This subsection says "SO_2 emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the emission limit of 50 ppmvd @ 0% excess 02 on a 7-day rolling average basis, provided that during such periods the owner or operator implements good air pollution control practices to minimize SO_2 emissions." As we have noted above, this is inconsistent with CAA requirements that SIP emission limits apply at all times, including periods of startup, shutdown, and malfunction (SSM).

Response to H-15: See response to comment H-5 regarding the inclusion of SSM Provisions.

H-16 [Submitted by EPA Region 8]: IX.H.11.g.i.B.I: This subsection requires compliance "By no later than January 1, 2018." Please explain why an earlier date would not be achievable.

Response to H-16: At least three of the four refineries listed in Section IX.H.12 are installing new equipment to meet the PM emission limits listed in Section IX.H.11.g.i.B.I. These items represent large capital investments with significant lead times, engineering, construction, startup, shakedown and testing involved. This date was reached through negotiation with the sources, and allowed for a full year of operation prior to the January 1, 2019, attainment date.

H-17 [Submitted by EPA Region 8]: IX.H.11.g.i.B.II: This subsection requires a stack test once every five years at FCCUs for PM emissions. Please explain why once every five years is considered sufficient frequency.

Response to H-17: The RACT determination was to apply the requirements of 40 CFR 60 (NSPS) Subpart Ja to each refinery FCCU. This was expressed in the Refinery General RACT Report (dated 10-1-2013) included in the TSD. Specifically, in the last paragraph on page 2 of that report is included both reference to Subpart Ja, as well as reference to UDAQ's contractor who established that subpart as the common element for particulate control at refinery FCCUs. Under the requirements of Subpart Ja, §60.102a(b) does not establish a particular testing frequency, only the specific limitation that applies. Chevron has been operating well below the required emission limit and has previously conducted test results demonstrating this. Tesoro and Holly are both installing wet gas scrubbers which need only demonstrate initial compliance and will then be able to demonstrate proper operation and maintenance with SO_2 and NO_x emission values, emissions of which are also controlled by the same control device. Big West's in-stack FGF is a mechanical filtration system which also need only demonstrate initial compliance. Periodic stack testing to demonstrate proper maintenance is all that is required following this initial demonstration test. In addition, Big West's total particulate emissions from the FCCU are less than 25 tons per year, below the level at which UDAQ would normally even require offsets under the PM_{10} nonattainment program, and well below the level at which stack testing is normally required. Therefore, a stack test every five years is appropriate.

H-18 [Submitted by EPA Region 8]: IX.H.11.g.i.B.III: This subsection says "PM emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the emission limit. . ." As we have noted above, this is inconsistent with CAA requirements that SIP emission limits apply at all times, including periods of startup, shutdown, and malfunction (SSM).

Response to H-18: See response to comment H-5 regarding the inclusion of SSM Provisions.

H-19 [Submitted by EPA Region 8]: IX.H.11.g.ii.A: We have several comments on this subsection:
1) This subsection requires compliance "By no later than January 1, 2018." Please explain why an earlier date would not be achievable.

2) This subsection says " ... except during periods of startup, shutdown, or malfunction." As we have noted above, this is inconsistent with CAA requirements that SIP emission limits apply at all times, including periods of startup, shutdown, and malfunction (SSM).

3) This subsection says "Compliance shall be based on a rolling average of 365 days." Please explain how averaging times longer than 24 hours can represent RACT in a plan that is intended to attain a 24-hour NAAQS.

4) This subsection specifies a limit of 60 ppm for hydrogen sulfide (H_2S) in refinery plant gas. This sort of limit is normally set in lieu of SO_2 emission limits at individual emitting units that burn plant fuel gas. Please explain how this limit was factored into the attainment modeling, i.e., were plantwide allowable SO_2 emissions calculated using this limit?

Response to H-19:

1) At least two of the four refineries listed in Section IX.H.12 are installing new equipment to meet the H_2S emission limits listed in Section IX.H.11.g.ii.A. These items represent large capital investments with significant lead times, engineering, construction, startup, shakedown and testing involved. This date was reached through negotiation with the sources, and allowed for a full year of operation prior to the January 1, 2019, attainment date.

2) See response to comment H-5 regarding the inclusion of SSM Provisions.

3) Following the use of sulfur recovery plants/sulfur recovery units (SRUs), the sulfur content of refinery fuel gas is not particularly variable. The gradual addition of SRU upgrades such as tail gas

treatment units, redundant systems, enhanced amine systems and the like have only reduced this variability. It is no longer necessary to determine the daily H_2S content of refinery fuel gas. Rather, these units have become so efficient at removing sulfur from refinery fuel gas, that additional control systems for reducing sulfur emissions from the SRUs themselves are now the focus. Hence the addition of such devices as tail gas incineration (TGI) and wet gas scrubbing. The purpose of a 365-day rolling average H_2S fuel gas limit is to track performance of the SRU system over a period of time – ensuring proper maintenance and allowing the source to spot potential upward emission trends.

4) No. Plant-wide allowable emission limits were already included in the model as discussed above (see previous response regarding annual and daily SIP emission Caps). This limit on refinery fuel gas H_2S content is included in addition to these individual plant-wide SO_2 SIP Caps as a specific RACT requirement which can be used to in order to achieve those reductions that established the SIP Caps.

H-20 [Submitted by EPA Region 8]: IX.H.11.g.iii.A: This subsection requires compliance "as soon as practicable but no later than January 1, 2018." Please explain why an earlier date would not be achievable. We do not view the phrase "as soon as practicable" to be practically enforceable; thus, it is not a meaningful addition to the date deadline and does not help meet CAA section 172(c)(1)' s requirement that RACM/RACT be implemented "as expeditiously as practicable," or CAA section 189(a)(l)(C)'s requirement that "reasonably available control measures for the control of [$PM_{2.5}$] shall be implemented no later than ... 4 years after designation ... "

Response to H-20: We will remove the "as soon as practicable but" language as per EPA's request. At least two of the four refineries listed in Section IX.H.12 are installing new equipment to meet the H_2S emission limits listed in Section IX.H.11.g.iii.A. These items represent large capital investments with significant lead times, engineering, construction, startup, shakedown and testing involved. This date was reached through negotiation with the sources, and allowed for a full year of operation prior to the January 1, 2019, attainment date. As no credit for refinery VOC reductions was claimed by UDAQ in the modeled attainment test as discussed in the Refinery General RACT Report (page 11), UDAQ established a final "no later than" dates by which compliance would need to be demonstrated for each VOC control methodology.

H-21 [Submitted by EPA Region 8]: IX.H.11.g.iii.A.I: This subsection contains exemption language "in lieu of 40 CFR 63 .654(b)." Please explain where this exemption language comes from, what its significance is in terms of VOC emissions, and why it should be considered reasonable for inclusion in the $PM_{2.5}$ SIP. We could not find it in 40 CFR 63, subpart CC (National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries). Please also explain why there is an exemption from requirements on heat exchangers when the process fluid contains less than 10% by weight VOCs. What is the basis for 10%? 10% VOCs in a fluid seems high.

Response to H-21: Exemption (a) of this section refers to pressurized heat exchangers that serve to prevent the movement of dissolved VOCs across the heat exchanger by means of maintaining a positive pressure differential. By preventing the transfer of VOCs across the heat exchanger, the cooling water is kept clean of VOC contamination. Subsequently, when that cooling water is returned to the cooling tower, no VOC emission can take place.

Similarly, exemption (b) prevents the transfer of VOCs by using an intermediary cooling fluid between the process fluid (which may contain VOC contamination) and the cooling water (which should remain free of VOC contamination). However, the commenter is incorrect in stating that the process fluid contains less than 10% VOCs. The draft rule requires that the **intermediary cooling fluid** contain less than 10% VOC by weight (emphasis added). By limiting the amount of VOCs contained in this intermediary fluid, one necessarily limits the potential VOC contamination of the cooling water and subsequent emission/release from the cooling tower.

The commenter is also incorrect in that both of these exemptions are found in 40 CFR 63.654(b); specifically, paragraphs (1) and (2). Although paragraph (2) lists 5% by weight total organic HAP rather than 10% by weight VOC. As this SIP is concerned with VOCs as a precursor to fine particulate formation and not the more restrictive category of organic HAPs (the focus of the MACT standard), this value was expanded slightly to account for non-HAP VOCs.

H-22 [Submitted by EPA Region 8]: IX.H.11.g.iv.A: This subsection requires compliance "as soon as practicable but no later than January 1, 2018." Please explain why an earlier date would not be achievable. We do not view the phrase "as soon as practicable" to be practically enforceable; thus, it is not a meaningful addition to the date deadline and does not help meet CAA section 172(c)(l)'s requirement that RACM/RACT be implemented "as expeditiously as practicable," or CAA section 189(a)(l)(C)'s requirement that "reasonably available control measures for the control of [PM2 s] shall be implemented no later than .. . 4 years after designation ... "

Response to H-22: We will remove the “as soon as practicable but” language as per EPA’s request. At least two of the four refineries listed in Section IX.H.12 are installing new equipment to meet the H_2S emission limits listed in Section IX.H.11.g.iii.A. These items represent large capital investments with significant lead times, engineering, construction, startup, shakedown and testing involved. This date was reached through negotiation with the sources, and allowed for a full year of operation prior to the January 1, 2019, attainment date. See previous comment regarding VOC emission reductions claimed as modeled credit.

H-23 [Submitted by EPA]: IX.H.11.g.v: We question why the flare restrictions in this section and its subsections are limited to "hydrocarbon flares." What is the intended scope of this term, and is it intended to address flaring of sulfur-containing gasses? Given that SO_2 is a $PM_{2.5}$ precursor, it would make sense to require compliance with NSPS Subpart Ja's SO_2-related provisions.

Response to H-23: With respect to flares, the provisions of NSPS Subpart Ja are primarily concerned with the establishment of a flare management plan – for the minimization of flaring events, and the development of flare gas recovery systems – for those refineries demonstrating a need or economic incentive. UDAQ recognizes that NSPS Subpart Ja still applies to each refinery generally, and should an individual refinery trigger the flare provisions of the subpart for flares other than the main hydrocarbon flares (an extremely remote possibility) then the subpart would kick in normally.

However, the remaining two types of flares present at the refineries listed in IX.H.12., specifically HF Alkylation flares and acid gas flares from sulfur recovery plants are true safety flares. Both flares exist to prevent the accidental release of far more hazardous materials, and no significant advantage would be gained by subjecting these flares to the provisions of IX.H.11.g.v. Flare management plans for either type of flare do not impact emissions by themselves. Installation of flare gas recovery at HF alkylation flares represents significant technical challenges. HF alkylation flares contain little useful recoverable fuel gas, and pose mechanical integrity and safety problems. SRU flare gas primarily consists of acid gases which pose a safety risk to plant personnel and are similarly limited in fuel gas usefulness.

H-24 [Submitted by EPA Region 8]: IX.H.11.g.v.A: This subsection requires compliance "Beginning January 1, 2018." Please explain why an earlier date would not be achievable. Also, please explain what is meant by "affecting a designated $PM_{2.5}$ non-attainment area ... " Is this defined somewhere? If so, this provision should include a cross-reference to ensure clarity. If not, the provision should be defined. In addition, while we support the requirement for the refineries to comply with Subpart Ja, we note that Subpart Ja contains an exemption from the H_2S limit in 40 CFR 60.1 03a(h) for releases to the flare as a result of relief valve leakage or other emergency malfunctions. As we have noted above, this is inconsistent with CAA requirements that the SIP emission limits apply at all times, including periods of startup, shutdown and malfunction (SSM). The SIP should note that this exemption does not apply under the SIP.

Response to H-24: At least two of the four refineries listed in Section IX.H.12 are upgrading or moving their flares as part of permitting actions taken commensurate with other RACT changes listed in Section IX.H.11.g. These changes represent large capital investments with significant lead times, engineering, construction, startup, shakedown and testing involved. This date was reached through negotiation with the sources, and allowed for a full year of operation prior to the January 1, 2019, attainment date.

The language regarding "affecting a designated $PM_{2.5}$ non-attainment area" should have said "significantly impacting a designated nonattainment area". Due to the location of the refineries with respect to the nonattainment boundary, this situation is highly unlikely to result. However, as this scenario has previously existed with respect to the PM_{10} SIP, UDAQ felt it was best to include such a provision in this case as well. References to "significantly impact" are found in 40 CFR 51 Appendix S.

Please also see response to H-5 regarding the inclusion of SSM Provisions.

H-25 [Submitted by EPA Region 8]: IX.H.11.g.v.B: This subsection requires compliance "By no later than January 1, 2019." Please explain why an earlier date would not be achievable. Also, this subsection says "except during periods of startup, shut down, or malfunction." As we have noted above, this is inconsistent with CAA requirements that SIP emission limits apply at all times, including periods of startup, shutdown, and malfunction (SSM).

Response to H-25: At least two of the four refineries listed in Section IX.H.12 are upgrading or moving their flares as part of permitting actions taken commensurate with other RACT changes listed in Section IX.H.11.g. These changes represent large capital investments with significant lead times, engineering, construction, startup, shakedown and testing involved. Only one of the refineries currently has a flare gas recovery system installed, while the remaining three would require integration with these other capital projects which were already designed, planned and established. The designated compliance date was established late in the negotiation phase with all the refineries. As the reductions achieved through implementation of flare gas recovery are minimal, and integration with other planned RACT projects was a worthwhile goal, UDAQ agreed to the listed date. This still allows for the flare gas recovery systems to be online and operational by the NAAQS attainment date of January 1, 2019.

Also, please see response to comment H-5 regarding the inclusion of SSM Provisions.

H-26 [Submitted by EPA Region 8]: IX.H.11.g.vi.A: This subsection requires compliance "Beginning January 1, 2017." Please explain why an earlier date would not be achievable.

Response to H-26: Several refineries are undergoing large scale projects to implement the new RACT controls listed in Section IX.H.11g and IX.H.12. As a part of these projects, some changes in tankage are taking place. In many cases, these changes may make it easier for the source to standardize tank degassing operations rather than needing to use a variety of methods and multiple 3rd party contractors. As these 3rd party contractors occasionally require separate authorization from UDAQ to conduct their operations, UDAQ is grateful for the reduction in paperwork and workload. As no credit was taken in the modeled attainment test for VOC reductions from tank degassing, the establishment of a January 1, 2017, compliance date was reasonable to UDAQ.

H-27 [Submitted by EPA Region 8]: IX.H.11.g.vi.B: This subsection says "These degassing provisions shall not apply while connecting or disconnecting degassing equipment." Please explain the basis for this exemption, i.e., why should it be necessary to exhaust VOCs to the atmosphere while connecting or disconnecting degassing equipment?

Response to H-27: This is not, as implied by the commenter, an open allowance for the source to exhaust VOCs. The exemption in IX.H.11.g.vi.B refers to the requirement in the previous paragraph to not allow the tank to be opened to the atmosphere unless those emissions of VOC are controlled. UDAQ agreed it was reasonable to allow for an exemption during the extremely brief period when degassing equipment was being connected or disconnected – as it could be argued that the source violated the provisions of IX.H.11.g.vi.A during that brief interval.

H-28 [Submitted by EPA Region 8]: For all four petroleum refineries, draft SIP subsection IX.H.12 proposes source wide emission limits for $PM_{2.5}$, SO_2 and NO_x in tons per day (tpd) and tons per rolling 12-month period. No other types of limits are proposed. The RACT Evaluation Reports for the refineries do not give any indication what emission limits in tons per day might represent RACT. Please explain how the proposed emission limits in tons per day were calculated and determined to represent RACT. Please also explain how rolling 12-month averages can represent RACT in a plan that is intended to attain a 24-hour NAAQS.

Response to H-28: There are three sets of limits that all work in conjunction. The rolling 12-month averages are based on overall RACT reductions, taking into account each RACT control method listed in the RACT Evaluation Reports based on each refinery's individual previous PTE total. Unlike the majority of major point sources in the SIP, each refinery was modeled using its annual PTE which is set by its SIP Cap allowables. This was done because each refinery had a pre-existing SIP Cap established by the PM_{10} SIP which could be used as the basis to apply RACT controls. In order to ensure that the model translates into appropriate 24-hour NAAQS attainment, a daily SIP Cap allowable is also imposed. These SIP Caps are not simply the annual Caps divided by 365, as this would not allow for operational flexibility which is already assumed by many of the Refinery General Provisions. Instead these values are based on worse-case scenarios which will still allow each source to meet the General Provisions. These values are then compared with the worst case values produced by the SMOKE preprocessor. As the source cannot operate at this daily value continuously and still be in compliance with the Refinery General Provisions, this provides a check on short to medium term emission "expansion" while still allowing immediate short-term flexibility and bringing us towards attainment of the NAAQS.

H-29 [Submitted by EPA Region 8]: According to the RACT Summary Table, the Cooling Tower, Flares, Fugitives and Tanks VOC control methods at the refineries are not required for implementation until 2019. The VOC emissions involved are estimated as significant, at least 1,300 tpy, according to the Table. Please explain why an earlier date would not be achievable.

Response to H-29: As no credit for refinery VOC reductions was claimed by UDAQ in the modeled attainment test as discussed in the Refinery General RACT Report (page 11), UDAQ established final "no later than" dates by which compliance would need to be demonstrated for each VOC control methodology. These dates were reached after negotiation with the refineries, and the specific requirements for each are actually listed in the general refinery requirements section of IX.H.11.g; specifically IX.H.11.g.iii – Heat Exchangers (cooling towers), iv – LDAR (fugitives), v – Flares, vi – Tank Degassing.

The RACT summary table is not an official SIP document but was developed to show the public the sources that underwent a RACT analysis and the reduction in criteria pollutants that would be realized due to implementation of the identified control. The table was developed early in the RACT evaluation process but has not been updated to accurately reflect changes that have occurred through the evaluation process.

H-30 [Submitted by EPA Region 8]: Sulfur Recovery Units (SRUs) are identified as RACT in the RACT Evaluation Reports for the refineries, but no level of control efficiency is identified as RACT. Draft SIP subsections IX.H.11 and IX.H.12 do not specify any level of control efficiency that the SRUs must achieve. We consider it essential to specify a level of control efficiency as RACT and would expect 95% or better control. Please supplement the TSD with a discussion of what level of control should be expected for the SRU at each refinery and include that level of control in draft SIP subsection IX.H.11 or IX.H.12.

We also note that only one of the four refineries (Chevron) is required to measure SO_2 emissions from the SRU, via CEMS. The draft SIP should require all four refineries to do this. See related comment above on IX.H.11.g.

Response to H-30: The sulfur recovery units listed as RACT already exist and have been in operation at the four refineries for many years. They were installed as a requirement of the 1994 PM_{10} SIP and have been in operation since that initial installation. The original PM_{10} SIP requirement of requiring 95% efficient SRUs can be found in Section [~~IX.H.2.a.M~~] IX.A.2.1.M– Petroleum Refineries, Paragraph A, subparagraph 1). This requirement is not being removed or altered in any way by this SIP, and the two documents are designed to be used in conjunction, hence the non-overlapping numbering scheme.

We agree with the position that a CEM is the appropriate method for determination of SO_2 emissions from the SRU, and will adjust the language for each of the compliance demonstration methodologies to make this clear. An SO_2 CEM is currently the compliance tool being used at each refinery in any event.

H-31 [Submitted by UPA]: *H.11.g.i.A.III—To* be consistent with the startup shutdown malfunction language in *"Limits on Refinery Fuel Gas", and "FCCU PM Emissions"* UPA proposes this paragraph to be modified as follows:

> SO_2 emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the emission limits in I., II. above provided that during such periods the owner or operator implements good air pollution control practices to minimize SO_2 emissions.

Response to H-31: See response to H-5 regarding the inclusion of SSM Provisions.

H-32 [Submitted by UPA]: *H.11.g.iii.A.—To* provide flexibility if EPA approves additional cooling tower monitoring methods, UPA proposes the following modification to the paragraph:

> ...The owner or operator may elect to use another method other than the Modified El Paso Method if approved by the Director or EPA.

Response to H-32: See response to H-21 and H-29 regarding the use of alternative cooling tower monitoring methods.

H-33 [Submitted by UPA]: *H.11.g.iv.*— UPA proposes adding an additional paragraph as follows:

> 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.

Response to H-33: See response to H-[~~22~~]49 regarding the inclusion of Sustainable Skip Period language to requirement H.11.g.iv.

H-34 [Submitted by UPA]: *H.11.g.v.* — Based on the analysis done by the State's own contractor Flare Gas Recovery exceeds both the technical and economic basis for RACT. EPA recognized this in establishing the NSPS Ja rule which was finalized in September 2012. NSPS Subpart Ja represents Best Determined Technology (BDT). In NSPS Ja EPA set BDT as requiring a Flare Management Plan (FMP) and implementation of Flare Gas Recovery only where economically justified or required to meet sulfur limitations. The rule proposed by the state exceeds BDT (and hence RACT) as determined by EPA in NSPS Ja.

In addition, emission reductions claimed by the state will be met by the FMP's and other NSPS Ja requirements. Additional reductions from the blanket Flare Gas Recovery requirement are minimal.

UPA recommends requiring each refinery to meet the requirements of NSPS Ja as stated in paragraph A, and remove paragraph B from the SIP.

Response to H-34: We disagree with this comment. Flare gas recovery was determined to be RACT as approved by the Utah Air Quality Board on December 4, 2013.

H-35 [Submitted by UPA]: *H.11.g.v.B* **-** As discussed in section 2.7 of the Refinery Technical Support Document, recovery of gases from HF alkylation and acid gas from sulfur recovery units poses significant technical challenges. Should the state reject UPA's previous recommendation and require Flare Gas Recovery, to clarify the rule's intent UPA proposes modifying the language to the following:

> ... except during periods of startup, shutdown, and malfunction. Flare gas recovery is not required for dedicated SRU flares, SRU flare header systems, nor HF flare header systems.

Response to H-34: See response to H-5 regarding the inclusion of this clarifying sentence.

H-35 [Submitted by HEAL]: To assist HEAL with our analysis of the four refineries' emissions, and determine whether they had been properly subject to a RACT analysis, we secured the services of an expert, Cindy Copeland. Ms. Copeland has worked on air quality issues for over 10 years, including working at U.S. EPA in the Air Program, for five years as the Particulate Matter Program Manager.

Ms. Copeland has authored a document, "Comments on Control Strategies for Key Stationary Sources in Utah's Proposed $PM_{2.5}$ SIP and Accompanying Part H Requirements," which we are submitting today along with our comments. It offers some initial thoughts generally on the SIP, but is primarily focused on refinery emissions and how those can be better controlled.

We are very pleased with the results of Ms. Copeland's thorough work and report and are confident it offers multiple opportunities for boosting the pollution reductions contained in the SIP. Her recommendations stand as HEAL's input on refinery pollution.

However, we wanted to offer one addition point to buttress her work. We are struck by the fact that the refineries and the Division concurred that several key proposed pollution control technologies were not RACT because they were "economically infeasible" – even though Holly Refinery is instituting those very strategies as part of its expansion plan. Specifically, the Holly refinery – as part of its Approval Order – has agreed to install wet gas scrubbers on two FCCU units; SCR on three heaters and boiler #8; and to replace all gas-fired compressors with electric compressors by 2017.

These technologies were considered and rejected by the other refineries to varying degrees. The Division has apparently agreed. (In just one of many examples, see p.3 of the RACT Evaluation Report of the Tesoro refinery, in which the Division rejects the wet gas scrubber technology to control $PM_{2.5}$ at Tesoro because it's "far more expensive than any of the other options." See: http://www.airquality.utah.gov/Pollutants/ParticulateMatter/PM 25/SaltLakeProvo/docs/ tsd/chapter5/5c/e-Tesoro%20TSD%2010-1-13.pdf.) Yet, given that they will be installed at Holly, aren't they by definition "reasonably available" to a northern Utah refinery?

We would urge the Division and Board to require the prompt installation of all pollution control technologies planned by Holly Refinery at the facilities operated by Tesoro, Chevron, Big West and Silver Eagle as well.

Again, for a wide range of additional recommendations, please refer to "Comments on Control Strategies for Key Stationary Sources in Utah's Proposed $PM_{2.5}$ SIP and Accompanying Part H Requirements," by Cindy Copeland and provided as an appendix to this document.

Response to H-35: With respect to comments on RACT, UDAQ thanks the commenter for the comment. While final RACT determinations were made at the December 4, 2013, meeting of the Utah Air Quality Board when it voted to accept SIP Subsection IX.A.21: Control Measures for Area and Point Sources, Fine Particulate Matter, $PM_{2.5}$ SIP for the Salt Lake, UT Nonattainment Area and SIP Subsection IX.A.22: Control Measures for Area and Point Sources, Fine Particulate Matter, $PM_{2.5}$ SIP for the Provo, UT Nonattainment Area, UDAQ anticipates the need to submit a new BACT/RACT analysis as part of a Subpart 4 Serious $PM_{2.5}$ Nonattainment Area SIP in the near future, and would invite the commenter to resubmit this comment at that time.

H-36 [Submitted by Wasatch Clean Air Coalition]: The SIP requires the following:
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.

A 3-hour average cannot be enforced by a stack test every 5 years. Refineries need to comply with § 60.105a (b) (1) The owner or operator shall install, operate, and maintain continuous parameter monitor systems (CPMS) to measure and record operating parameters for each control device…

Response to H-36: The RACT determination was to apply the requirements of 40 CFR 60 (NSPS) Subpart Ja to each refinery FCCU. This was expressed in the Refinery General RACT Report (dated 10-1-2013) included in the TSD. Specifically, in the last paragraph on page 2 of that report is included both reference to Subpart Ja, as well as reference to UDAQ's contractor who established that subpart as the common element for particulate control at refinery FCCUs. Under the requirements of Subpart Ja, §60.102a(b) does not establish a particular testing frequency, only the specific limitation that applies. Chevron has been operating well below the required emission limit and has previously conducted test results demonstrating this. Tesoro and Holly are both installing wet gas scrubbers which need only demonstrate initial compliance and will then be able to demonstrate proper operation and maintenance with SO_2 and NO_x emission values, emissions of which are also controlled by the same control device. Big West's in-stack FGF is a mechanical filtration system which also need only demonstrate initial compliance. Periodic stack testing to demonstrate proper maintenance is all that is required following this initial demonstration test. In addition, Big West's total particulate emissions from the FCCU are less than 25 tons per year, below the level at which UDAQ would normally even require offsets under the PM_{10} nonattainment program, and well below the level at which stack testing is normally required. Therefore, a stack test every five years is appropriate.

However, commenter's reference to § 60.105a(b)(1) is not without merit. Continuing to read past the ellipsis in the citation, the full sentence reads as follows:

The owner or operator shall install, operate and maintain continuous parameter monitor systems (CPMS) to measure and record operating parameters for each control device according to the applicable requirements in paragraphs (b)(1)(i) through (v) of this section.

Paragraphs (i) through (v) of that section discuss the various parameters to be monitored depending on whether the final control device is an ESP, wet scrubber, fabric filter or cyclone, and then some general requirements such as average coke burn-off rate and hours of operation. These parameters, while not direct measurements of air emissions, do serve as inputs to the calculation methodology for determination of daily $PM_{2.5}$ emission totals for each refinery under its specific $PM_{2.5}$ SIP Cap section of IX.H.12. Consequently, a new paragraph IX.H.11.g.i.B.IV will be added as follows:

IV. 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 $PM_{2.5}$ emissions as appropriate.

CHEVRON

H-37 [Submitted by EPA Region 8]: EPA Comment 1: Page 8 of the RACT Evaluation Report identifies NO_x RACT for Process Heaters and Boilers as replacement of boilers 1, 2 and 4 with ULNB capable of achieving a NO_x emission rate of 0.03 lb/MMBtu. The Report says a NO_x emission reduction of 110 tpy is expected. This expected reduction is also cited in the RACT Summary Table, to be achieved by 2017. However, draft SIP subsection IX.H.12.g. does not include a requirement to replace boilers 1, 2 and 4. The SIP subsection specifies the calculations to be used for demonstrating compliance with sourcewide NO_x emission limits, but it is not apparent whether any of these calculations take into account any requirement to replace the boilers with ULNB. Please explain. If Chevron is being credited with emission reduction due to installation of new controls as RACT, then this needs to be reflected as proposed RACT in the SIP. Please also explain why an earlier date than 2017 would not be achievable.

Response to H-37: The above cited RACT controls were taken into account in determination of both the annual and daily SIP emission Caps. The replacement of these three boilers was chosen by the source as one possible method for reaching the specific emission. However, individual control methodologies are not being included as specific requirements in the language of the SIP as this unnecessarily limits both the source and the agency from including better, higher efficiency controls, should such become available. Should the source elect to replace the boilers with units that have only LNB but also SCR, or with two larger boilers (versus the three currently anticipated), any of these could be considered as representing a SIP compliance issue without first undertaking a SIP modification – a lengthy and arduous process. By electing to require only a final emission limitation for these sources to maintain, UDAQ ensures that equivalent emission reductions are achieved without binding the source unnecessarily.

H-38 [Submitted by EPA Region 8]: Page 7 of Chevron's own RACT analysis, dated March 11, 2013, contains an analysis for three rich burn reformer compressor engines with a potential to emit of 159.2 tpy NO_x each. Using air-to-fuel ratio (AFR) controls and Non-Selective Catalytic Reduction (NSCR) at a cost of $4,966/ton was considered by Chevron to be economically infeasible, but we find that conclusion to be questionable. Though Chevron states that AFR + NSCR will be implemented in the future "within one year of the date of entry of the pending draft agreement with EPA," it would appear to be a logical requirement for the $PM_{2.5}$ SIP. Why was it not discussed in the state's RACT Evaluation Report and why is it not proposed to be required for this SIP?

Response to H-38: This was missed during UDAQ's review of RACT, and was not included during UDAQ's modeled evaluation of NAAQS attainment demonstration. However, UDAQ does not agree with EPA's assessment of the PTE of these three compressor engines. The three compressor engines to which UDAQ assumes EPA is referring – Compressor engines K35001, K35002 and K35003, rated at 16 MMBtu/hr combined – have a total PTE of 84.3 tons of NO_x per year for all three engines. UDAQ is unable to locate the specific values to which EPA refers. Unfortunately, Chevron's RACT submittal is provided in multiple parts – each of which restarts page numbering – so there are multiple page 7s. The total NO_x reduction available should we require this control would be approximately 76 tons per year.

We anticipate the need to submit a new BACT/RACT analysis as part of a Subpart 4 Serious PM2.5 Nonattainment Area SIP in the near future, and this issue should be addressed at that time.

H-39 [Submitted by EPA]: Under "Source-wide $PM_{2.5}$," draft SIP subsection IX.H.l2.g.i. reads, "Filterable PM2.5 emissions shall be determined by applying various emission factors ... " This language is imprecise/vague. Please delete the word "various."

Response to H-39: We will remove the word “various” as requested.

H-40 [Submitted by EPA]: In the same paragraph, the language reads, "Unless otherwise specified by an Approval Order .. . " This is not approvable language. EPA needs to be able to approve any revisions to the methods for determining compliance, unless the SIP establishes enforceable, replicable procedures for modifying the methods. For example, where a revision to an emission factor is established through a simple stack test, we have been willing to approve SIP language that describes the process. The process should include notice to use of the stack test date, results, and new emission factor.

Response to H-40: See response to H-[~~5~~]107 regarding the language “Unless otherwise specified by an Approval Order.”

H-41 [Submitted by EPA]: In a later paragraph, the language reads, "Daily gas consumption by all boilers and furnaces shall be measured by meters that can delineate the flow of gas to the indicated emission points." The phrase "indicated emission points" is undefined. The-SIP language needs to specify the emission points that are covered.

Response to H-41: As discussed previously, the term “indicated emission points” was previously defined in the sentence as “all boilers and furnaces.”

H-42 [Submitted by EPA]: In a later paragraph, the language reads, "By no later than January 1, 2017, Chevron shall conduct stack testing to establish the ratio of condensable $PM_{2.5}$ from the FCC Catalyst Regenerator and SRUs. At that time the condensable fraction will be added and a new source-wide limitation shall be established in the AO." This is not approvable. There is no explanation why it would not be possible to establish the condensable ratio now, through testing, use of emission factors, or estimates. The SIP is supposed to evaluate RACT for condensable and filterable PM. The SIP cannot defer the establishment of limits. And the SIP must contain the RACT limits, not an AO.

Response to H-42: See response to H-8 regarding Condensable $PM_{2.5}$ Limits.

H-43 [Submitted by EPA]: Source-wide NO_x provisions: Language reads, " ... the most recent listing of these emission factors is maintained in Chevron's AO." This is not approvable. The SIP must contain the relevant emission factors for RACT, not an AO.

Response to H-43: See response to H-[~~5~~]107 regarding the language “Unless otherwise specified by an Approval Order,” and Setting Emission Factors by Performance Testing.

H-44 [Submitted by EPA]: Source-wide SO_2 provisions: The RACT Evaluation Report does not identify any level of control efficiency as RACT for SO_2 emissions from the SRU at Chevron, nor does this appear in draft SIP subsections IX.H.11. or IX.H.l2.g. We consider it essential to specify a level of control efficiency as RACT and would expect 95% or better control. Please supplement the TSD with a discussion of what level of control should be expected for the SRU at Chevron and include that level of control in draft SIP subsection IX.H.11 or IX.H.l2.g.

Response to H-44: See response to H-30 regarding the existing SRUs at each refinery, and the retention of SIP Section [~~IX.H.2.a.M.A.1~~]IX.A.2.1.M.A.1).

H-45 [Submitted by EPA Region 8]: Draft SIP subsection IX.H.12.g relies on NO_x, SO_2 and H_2S CEMS to determine some of the emissions and emission factors, but this subsection of the draft SIP doesn't clearly require the operation of CEMS. This does not appear to be addressed by the General Requirements for Petroleum Refineries at draft SIP subsection IX.H.11 .g. Please see our related comment on IX.H.11.g.

Response to H-45: See response to H-13 on SIP Section IX.H.11.g as it relates to Section IX.H.11.f.

H-46 [Submitted by EPA Region 8]: There are no proposed requirements to report excess emissions. Please explain how this will be addressed.

Response to H-46: The reporting of excess emissions remains a requirement of UDAQ's existing breakdown rule and emissions inventory reporting requirements. These can be found at R307-107 and R307-150 respectively. Every approval order requires the permittee to comply with the requirements for breakdown reporting. No additional SIP reporting requirements are necessary.

H-47 [Submitted by Chevron]: H.11.g.i.A.III – To be consistent with the startup/shutdown/malfunction/language in "*Limits on Refinery Fuel Gas*", and "*FCCU PM Emissions*" Chevron proposes this paragraph to be modified as follows:

> SO_2 emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the emission limits in I., II. above provided that during such periods the owner or operator implements good air pollution control practices to minimize SO_2 emissions.

Response to H-47: We agree with this change. The language as suggested by the commenter is acceptable to UDAQ. It will be included in section H.11.g.i.A.III. Please also see response to H-5 regarding SSM provisions.

H-48 [Submitted by Chevron]: H.11.g.iii.A – To provide flexibility if EPA approves additional cooling tower monitoring methods, Chevron proposes the following modification to the paragraph:

> ... The owner or operator may elect to use another method other than the Modified El Paso Method if approved by the Director or EPA.

Response to H-48: While UDAQ agrees with the concept of this comment, the language as it currently exists provides the requested flexibility. The terms "another EPA-approved method" and "if approved by the Director" are the standardized language preferred by the Division to address exactly the situation addressed by the commenter.

H-49 [Submitted by Chevron]: H.11.g.iv – Chevron proposes adding an additional paragraph as follows:

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

Response to H-49: UDAQ agrees with this change. The language suggested by the commenter, will be added, with one correction. The word "proved" will be replaced with the word "provided." The new paragraph will be added as paragraph B. of H.11.g.iv as follows:

> *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.*

H-50 [Submitted by Chevron]: H.11.g.v – Based on the analysis done by the State's own contractor Flare Gas Recovery exceeds both the technical and economic basis for RACT. EPA recognized this in establishing the NSPS Ja rule which was finalized in September 2012. NSPS Subpart Ja represents Best Determined Technology (BDT). In NSPS Ja EPA set BDT as requiring a Flare Management Plan (FMP) and implementation of Flare Gas Recovery only where economically justified or required to meet sulfur limitations. The rule proposed by the state exceeds BDT (and hence RACT) as determined by EPA in NSPS Ja.

In addition, emission reductions claimed by the state will be met by the FMP's and other NSPS Ja requirements. Additional reductions from the blanket Flare Gas Recovery requirement are minimal. Chevron recommends requiring each refinery to meet the requirements of NSPS Ja as stated in paragraph A, and remove paragraph B from the SIP.

Response to H-50: UDAQ disagrees with this comment. Flare gas recovery was determined to be RACT as approved by the Utah Air Quality Board on December 4, 2013.

H-51 [Submitted by Chevron]: H.11.g.v.B – As discussed in section 2.7 of the Refinery Technical Support Document, recovery of gases from HF alkylation and acid gas from sulfur recovery units poses significant technical challenges. Should the state reject Chevron's previous recommendation and require Flare Gas Recovery, to clarify the rule's intent Chevron proposes modifying the language to the following:

> ... except during periods of startup, shutdown, and malfunction. Flare gas recovery is not required for dedicated SRU flares, SRU flare header systems, nor HF flare header systems.

Response to H-51: UDAQ agrees with this comment. The intention of the flare gas recovery requirement was to have it apply to hydrocarbon flares only, as should be evident from a reading of the technical support documentation – Section 2.7 as referenced by the comment.

The suggested additional clarifying sentence is acceptable. The sentence will be added to IX.H.11.g.v.B as requested.

H-52 [Submitted by Chevron]: New boiler installation date – part of Chevron's determined RACT was a replacement its [sic] boilers 1, 2 and 4. Due to the large capital cost and scope of the project Chevron requests until the end of 2018 to implement this project. This is more in line with the implementation timelines for the large capital expenditures required at other major point sources.

Response to H-52: We agree with this comment. We recognize that these items represent large capital investments with significant lead times, engineering, construction, startup, shakedown and testing involved. Although the RACT reductions from these boilers are specific only to NO_x emissions, the boilers will contribute to all three SIP Cap emission totals. Therefore, the source-wide limits of $PM_{2.5}$, NO_x and SO_2 will remain as found in SIP Sections IX.H.12.g.i, ii, and iii will be applied "no later than January 1, 2019".

H-53 [Submitted by Chevron]: H.13.g.ii – NO_x Limit implementation date – Chevron's source-wide NO_x limit of 2.1 tons per day is dependent on the replacement of boilers 1, 2 and 4, and hence should have a start date that is linked to the completion of the boiler replacement project.

Response to H-53: This comment is a request to modify the NO_x SIP Cap limit based on the implementation date of the three boilers being replaced. Please see the response to H-37 for details on how this will impact each of the SIP emission Caps.

H-54 [Submitted by Western Resource Advocates (WRA)]: The Emission Limits include source-wide $PM_{2.5}$, NOX and SO_2 emission limits for the Chevron Refinery. A source-wide emission limit should also be established for VOC at the refinery. Individual emission limits must be set at the major units or process points at the refinery, such as the FCCU. TechLaw recommended that the Director "should consider a 365-day NO_x limit for the FCCU to further encourage optimal NOX performance for the FCCU. An annual limit of approximately 40 to 45 ppmv appears achievable for the FCCU based on 2010 NOX CEMS data."

Response to H-54: See responses to H-52 and H-53 regarding setting source-wide VOC limits at a refinery, individual emission controls, and responses to H-4 and H-29 regarding the use of the RACT Summary Table. *See also* previous response regarding RACT Final Determination (H-35).

H-55 [Submitted by WRA]: While the Director proposes that boilers 1, 2 and 4 will be replaced with ULNB in 2017, this control is not, but must be part of, the Emission Limits. Moreover, while TechLaw recommends a NOX emission limit of 0.030 lbs/MMBtu for all boilers at the facility, a NOX limit of 0.0061 lb/MMBtu, which can be achieved using ultra low NOX burners, SCR or LTO, more accurately reflects RACT.

Response to H-55: See responses to H-52 and H-53 regarding individual emission controls. *See also* previous response regarding RACT Final Determination (H-35).

H-56 [Submitted by WRA]: The Chevron operates a delayed coking unit, which is a significant source of PM and VOC. BACT requires prohibiting the use of coker condenser water for coke quenching. This water is skimmed to remove the oil and then treated. The NSPS requires the coker to be vented to a recovery system until the pressure drops below 5 psig, when the steam vent can be opened to atmosphere. This establishes the floor for a RACT and requiring venting at even lower pressures is appropriate.

Response to H-56: See previous response regarding RACT Final Determination (H-35).

HOLLY FRONTIER

H-57 [Submitted by EPA Region 8]: The RACT Summary Table indicates that a Wet Gas Scrubber (WGS) will be installed for PM, SO_2 and NO_x control at proposed FCCU #2 by 2017, that Selective Catalytic Reduction (SCR) will be installed for NO_x control at heaters and boilers by 2017, that the compressors will be replaced with electric units for control of all pollutants by 2017, and that a WGS will be installed for SO_2 control at the Sulfur Recovery Unit (SRU) by 2017. Please explain why an earlier date would not be achievable.

Response to H-57: These items represent large capital investments with significant lead times, engineering, construction, startup, shakedown and testing involved. This date was reached through negotiation with the source based on the source's expected construction schedule after consideration of each factor.

H-58 [Submitted by EPA]: There are a number of instances where new controls are identified as RACT in the RACT Evaluation Report, and are credited with emission reductions in the RACT Summary Table, but are not required in draft SIP subsection IX.H.12.k:

i) Pages 5 and 6 of the RACT Evaluation Report identify RACT for PM2.s and SO_2 at proposed FCCU #2 as installation of WGS. The Report says reductions of 30 tpy for $PM_{2.5}$ and 260 tpy for SO_2 are expected. These expected reductions are also cited in the RACT Summary Table, to be achieved by 2017.

ii) Page 7 of the RACT Evaluation Report identifies RACT for NO_x at proposed FCCU #2 as installation of WGS-LoTOx. The Report says a NO_x reduction of 26.2 tpy is expected. This expected reduction is also cited in the RACT Summary Table, to be achieved by 2019.

iii) Page 9 of the RACT Evaluation Report identifies RACT for NO_x at Process Heaters and Boilers as installation of SCR on three process heaters (1 OH1, 30H1 and 30H2) and Boiler #8. The Report says a NO_x reduction of 35 tpy is expected. This expected reduction is also cited in the RACT Summary Table, to be achieved by 2017.

iv) Page 9 of the RACT Evaluation Report identifies RACT for all pollutants at the Compressors as replacement of the existing compressors with all electric equipment. The Report says the expected emission reductions are 1.6 tpy for PM2.s, 0.04 tpy for SO_2, 96.2 tpy for NO_x, and 4 tpy for VOC. These expected reductions are also cited in the RACT Summary Table, to be achieved by 2017.

v) Page 11 of the RACT Evaluation Report identifies RACT for SO_2 at the Sulfur Recovery Unit (SRU) as "continue to operate the WGS unit as a final SO_2 removal system for the existing SRU." The Report says a SO_2 reduction of 125 tpy from the 2008 baseline (modeled) inventory is expected. This expected reduction is also cited in the RACT Summary Table, to be achieved by 2017. Draft SIP subsection IX.H.12.k. specifies the calculations to be used for demonstrating compliance with sourcewide SO_2 and NO_x emission limits, but it is not apparent whether any of these calculations take into account any requirement to install and use new emission controls. Please explain. If Holly is being credited with emission reductions due to installation of new controls as RACT, then this needs to be reflected as proposed RACT in the SIP.

Response to H-58: The above cited RACT controls were taken into account in determination of both the annual and daily SIP emission Caps. However, individual control methodologies are not being included as specific requirements in the language of the SIP as this unnecessarily limits both the source and the agency from including better, higher efficiency controls, should such become available. By electing to require only a final emission limitation for these sources to maintain, UDAQ ensures that equivalent emission reductions are achieved without binding the source unnecessarily. See responses to H-4, H-29, H-52, and H-53 relating to individual emission controls, and the use of the RACT Summary Table.

H-59 [Submitted by EPA]: Page 14 of the RACT Evaluation Report proposes no changes to existing wastewater operations as VOC RACT for wastewater separators and drains. One option is presented as technically feasible (ensuring all drains are covered and routing the API separator vent gas to a control device for thermal combustion or oxidation), with potential 70% VOC control, but was not selected as RACT. One other area refinery (Chevron), however, operates a regenerative thermal oxidizer system in conjunction with covers and vent routing. Page 14 of the RACT Evaluation Report for Holly estimates VOC emission reductions as high as 31.6 tpy if a similar system were employed at Holly, but does not propose such a system, instead stating only that "further discussions on controlling wastewater VOC emissions need to be held." Since it is proven to be technically and economically feasible at another area refinery, why is it not proposed here? Please explain.

Response to H-59: Chevron's wastewater plant VOC emissions were significantly higher than those of the other three refineries. The Chevron refinery has had a well-established wastewater treatment system for longer than the other refineries. The system is also more extensive and was recently modernized. UDAQ believes that the estimates of potential VOC reductions from a wastewater system at the Big West Refinery to be overestimated, but has not yet had the opportunity to conduct on-site monitoring to determine a more appropriate value. This was stated clearly in the very next sentence on page 14 of the RACT Evaluation Report.

H-60 [Submitted by EPA]: Under "Source-wide PM2s," draft SIP subsection IX.H.12.k. reads, "$PM_{2.5}$ emissions shall be determined by applying various emission factors ... " This language is imprecise/vague. Please delete the word "various." Also, unlike Big West and Chevron, this language does not say "filterable." Was that an inadvertent omission?

Response to H-60: UDAQ will remove the word "various" as requested.

H-61 [Submitted by EPA]: In the same paragraph, the language reads, "Unless otherwise specified by an Approval Order ... " This is not approvable language. EPA needs to be able to approve any revisions to the methods for determining compliance, unless the SIP establishes enforceable, replicable procedures for modifying the methods. For example, where a revision to an emission factor is established through a simple stack test, we have been willing to approve SIP language that describes the process. The process should include notice to us of the stack test date, results, and new emission factor.

Response to H-61: UDAQ has revised the language of the two sentences of that paragraph to read as follows:

> *$PM_{2.5}$ emissions shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed above, the default emission factors to be used are as follows:*

H-62 [Submitted by EPA]: 6) Language in a later paragraph reads, "Daily natural gas and plant gas consumption shall be determined through the use of flow meters." There is no indication where these meters are located, for which emission points they are tracking the fuel consumption, and how they would delineate the flow of gas to the emission points. The SIP language needs to specify the emission points that are covered.

Response to H-62: While UDAQ believes this is self-evident based on previous sentences which established the default emission factors for NSPS vs non-NSPS equipment, UDAQ will adjust the sentence to read as follows:

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

Since the emission factor is provided in lb/MMscf, UDAQ does not feel it is necessary to specify that the flow meter provide results in cubic feet of gas flow.

H-63 [Submitted by EPA]: Source-wide SO_2 provisions: Language reads, " ... excluding routine SRU turnaround maintenance emissions." It is unclear why Holly needs this exemption when it is not proposed for the other refineries. As we explained in our comment on SIP subsection IX.H.1l.d, periods of exemption from emission limits are inconsistent with CAA requirements that SIP emission limits apply at all times, including periods of startup, shutdown, and malfunction. This comment applies also to periods of scheduled equipment maintenance.

Response to H-63: UDAQ disagrees with this comment. SRU turnaround maintenance does not qualify as startup, shutdown or maintenance. It is a specific non-routine event which occurs every 3-4 years at the Holly Refinery. Unlike the other refineries, which schedule SRU maintenance events during plant shutdowns, Holly performs SRU turnarounds which can result in SO_2 emissions which exceed the daily SO_2 Cap. These SRU turnarounds are always scheduled through UDAQ and during non-wintertime periods so as to avoid NAAQS violations. The SRU turnaround provision was not requested or needed by the other three refineries, and was therefore not included. As this event is a specific special occurrence, UDAQ has included it.

H-64 [Submitted by EPA]: There is no requirement for SO_2 CEMS or any other technique for accounting for SRU emissions of SO_2. It is our understanding that the SRU at each refinery has an SO_2 CEMS, which we would expect to be used to account for a portion of source-wide SO_2 emissions. See, for example, SIP subsection IX.H.12.g.iii for Chevron, which requires use of SO_2 CEMS in determining SO_2 emissions from the SRU. Please explain why this is not accounted for at Holly.

Response to H-64: See response to H-30 regarding the use of SO_2 CEMs at the SRUs.

H-65 [Submitted by EPA]: The RACT Evaluation Report does not identify any level of control efficiency as RACT for SO_2 emissions from the SRU at Holly, nor does this appear in draft SIP subsections IX.H.11. or IX.H.12.k. We consider it essential to specify a level of control efficiency as RACT and would expect 95% or better control. Please supplement the TSD with a discussion of what level of control should be expected for the SRU at Holly and include that level of control in draft SIP subsection IX.H.11 or IX.H.12.k.

Response to H-65: See response to H-30 regarding the existing SRUs at each refinery, and the retention of SIP Section [~~IX.H.2.a.M.A.1~~]IX.A.2.1.M.A.1).

H-66 [Submitted by EPA]: The source-wide SO_2 provisions include a provision that, "The sulfur content of the fuel oil shall be tested if directed by the Director." Why was this provision considered necessary for Holly? Chevron's source-wide SO_2 provisions also account for fuel oil, but do not include this particular provision. What is the import of this provision? If tests show a different sulfur content than the ASTM method, will the test results establish a new emission factor going forward? This is not explained.

Response to H-66: This provision is not required for the SIP and was brought over from Holly's AO in error. It will be removed.

H-67 [Submitted by EPA]: Unlike Big West and Chevron refineries, there is no requirement for NO_x CEMS or any other technique for accounting for catalyst regenerator emissions of NO_x at Holly. See, for example, requirement for NO_x CEMS at the Catalyst Regeneration System at Big West and requirement for NO_x CEMS at the FCC Regenerator at Chevron. Please explain why this is not accounted for at Holly.

Response to H-67: Unlike the Big West and Chevron Refineries, the two FCC Units at the Holly Refinery are subject to the provisions of 40 CFR 60 Subpart Ja prior to the issuance of the $PM_{2.5}$ SIP. This was demonstrated in the AO upon which most of the RACT analysis was based; which includes both a NO_x ppmvd limit and requires the use of a NO_x CEM to demonstrate compliance with those limits. However, those limits are identical to 40 CFR 60 Subpart Ja, as is the requirement for installation of a NO_x CEM. See 40 CFR 60.102a(b)(2) and 40 CFR 60.105a(f). As these requirements are already federal law, and the source is already subject to these provisions, UDAQ did not include them as this would be redundant.

H-68 [Submitted by EPA]: Draft SIP subsection IX.H.12.k relies on H_2S CEMS to determine some of the emissions and emission factors, but this subsection of the draft SIP doesn't clearly require the operation of CEMS. This does not appear to be addressed by the General Requirements for Petroleum Refineries at draft SIP subsection IX.H.11.g. Please see our related comment on IX.H.11.g.

Response to H-68: See response to H-13.

H-69 [Submitted by EPA]: There are no proposed requirements to report excess emissions. Please explain how this will be addressed.

Response to H-69: The reporting of excess emissions remains a requirement of UDAQ's existing breakdown rule and emissions inventory reporting requirements. These can be found at R307-107 and R307-150 respectively. Every approval order requires the permittee to comply with the requirements for breakdown reporting. No additional SIP reporting requirements are necessary.

H-70 [Submitted by Holly]: H.11.e.i.C-D – It is widely recognized that Methods 201 and 202 yield results for particulates that are significantly higher than reality, especially due to artifact formation when determining condensables. Instead of requiring methods that will results in extraordinarily high particulate matter results, and leaving only an option to use "other EPA-approved testing methods acceptable to the Director," the State should include more appropriate methods such as U.S. EPA CTM-039, which is a dilution sampling method. In addition, there are modifications to CTM-039 that increase sensitivity and make it even more accurate for measuring particulates from natural gas-fired equipment, which typically has lower PM emissions that [sic] the sources that Methods 201 and 202 are suited for. It would be best if the State specified this method and its modifications to prevent the development and submission of erroneous data. For further information on this issue, please refer to the comments submitted to DAQ on October 31, 2013 by Environmental Resources Management ("ERM") on behalf of the Utah Manufacturer's Association, Utah Mining Association, and Utah Petroleum Association at pages 3 and 4 (incorporated herein by reference).

Response to H-70: UDAQ must require the use of EPA approved methods. Concerns with the accuracy of those methods, and selection of the best methods for each particular source, should be resolved with UDAQ staff through protocol discussions prior to performing testing.

H-71 [Submitted by Holly]: H.11.g.iv – Implementing this requirement as proposed will require a significant initial effort as the regulations require monthly monitoring before moving to quarterly monitoring, Since existing components have been previously monitored subject to higher leak limits, we request that the State allow the use of prior monitoring to establish initial skip monitoring periods.

Response to H-71: See previous response to H-[~~22~~]49 regarding the inclusion of Sustainable Skip Period language to requirement H.11.g.iv.

H-72 [Submitted by Holly]: H.11.g.v.B – Recovery of gases from HF alkylation and acid gas from sulfur recovery units creates significant mechanical integrity and safety problems. We request that flare gas recovery not be required for sulfur recovery unit relief or hydrofluoric acid alkylation unit relief. Periods of startup, shut down, or malfunction are excluded, and we are assuming this includes unit purging with nitrogen as part of an orderly shutdown, since it would be undesirable to recovery that nitrogen purge in a flare gas recovery system and send it to fuel.

Response to H-72: UDAQ agrees with this comment. See previous response regarding HF alkylation unit flare gases and SRU relief flare gases. In regards to nitrogen purging as part of an "orderly shutdown," UDAQ recognizes orderly shutdown operations as constituting a shutdown, and therefore excluded as indicated by the commenter. However, while UDAQ agrees that the establishment of operational definitions could be useful, UDAQ believes that such definitions are best included as permit conditions.

H-73 [Submitted by Holly]: H.11.k – Company name. Please note that the name of our parent corporate entity is HollyFrontier Corporation, and the name of the refinery operating company is Holly Refining and Marketing Company – Woods Cross L.L.C.

Response to H-73: The comment is noted. The appropriate changes will be made to H.12.k.

H-74 [Submitted by Holly]: H.11.k.i – The particulate matter limit for Holly was assumed to include both filterable and condensable fractions. However, the limits for other sources, including the other 3 refineries, were set to include only the filterable fraction, with the stipulation on some of these to add the condensable limit for one or more individual pieces of equipment at a later date. We request that for purposes of the SIP, the particulate limit for Holly be specified for the filterable fraction only, consistent with other sources.

Response to H-74: The commenter is correct that some sources only have a filterable-fraction limit, with a "to be established" condensable-fraction condition. Many of these sources are adding new equipment and have been unable to test this equipment under actual operating conditions to determine a proper ratio of condensable to filterable particulate emissions. Deadlines for setting condensable limits were established for each source. While UDAQ recognizes that the Holly Refinery is unique among the four listed refineries in having these ratios predetermined and established at SIP publication, UDAQ does not recognize the benefit of removing these limits only to re-establish the exact same limits within a short time period. This benefit is of even less value when these limits already exist within a federally enforceable AO issued to the refinery.

H-75 [Submitted by Holly]: Please note also that the SIP limits are based upon a permit revision for Holly that, as of the date of this letter, as not been issued. The permit revision utilizes emission reduction technologies that are not possible without the equipment included in the revision.

Response to H-75: UDAQ acknowledges this comment. The AO DAQE-101230041-13 was issued on November 18, 2013.

H-76 [Submitted by Holly]: The emission limits under H.12.k were determined based on our pending permit modification. When the SIP is approved, the limitations are in effect. However, where equipment must be installed to effect the emission reductions that are reflected in the SIP and the permit modification, time for engineering, procurement, installation, and startup will be required. To allow for these activities, the SIP should include language that specifies that the limits are to be achieved no later than January 1, 2019.

Response to H-76: UDAQ agrees with this comment. The language of IX.H.12.k.i, ii and iii will be adjusted such that the SIP Caps will apply as of "no later than January 1, 2019". See response to H-3 regarding implementation schedules.

H-77 [Submitted by WRA]: The Emission Limits include source-wide $PM_{2.5}$, NOX and SO_2 emission limits for the Holly Refinery. A source-wide emission limit should be established for VOC at the refinery. Individual emission limits must be set at the major units or process points at the refinery, such as the FCCU. Such an approach is mandated as RACT – which is required for each emission unit – and is also required under Title V. Moreover, without limits on each emission unit, it is difficult, if not impossible, to compare emission limitations at this facility with other facilities in order to access whether RACT has been met.

Response to H-77: See previous responses regarding setting source-wide VOC limits at a refinery, individual emission controls, and the use of the RACT Summary Table, including H-4, 29, 52, and 53.

H-78 [Submitted by WRA]: According to the Director, 2019 projections show that $PM_{2.5}$ emissions from Holly will increase by 30.11 tpy and NOX emissions will increase by 84.42 tpy. Such emission increases are not acceptable as RACT. TechLaw states Holly's new FCCU will meet a 0.3 lbs/klb coke burn-off emissions limit. The existing FCCU must meet the same limit. Additional controls for the FCCUs should be evaluated for the RACT determination to curb emission increases at the facility.

Response to H-78: The emission increases cited by the commenter were part of a planned expansion of the Holly Refinery. During early development of the $PM_{2.5}$ SIP HollyFrontier discussed the planned expansion with UDAQ to ensure that while some actual emissions might increase, total allowable emissions would decrease as new controls were installed. The decrease in allowable emissions, especially in NO_x and SO_2 was significant (NO_x –322.9 and SO_2 –725.7 tons respectively).

The approach to attaining the NAAQS must be viewed across the entire non-attainment area, and not merely by attempting to mandate all sources must achieve emission reductions. The application of RACT is case-by-case and this means each source and each emission unit at each source must be reviewed individually. Simply dictating that “such emission increases are not acceptable as RACT” is not sufficient for the analysis. For further details, please see UDAQ’s individual RACT Evaluation Reports. See also previous response regarding RACT Final Determination (H-35).

TESORO REFINING AND MARKETING COMPANY – SLC REFINERY

H-79 [Submitted by EPA Region 8]: Page 14 of the RACT Evaluation Report proposes no changes to existing wastewater operations as VOC RACT for wastewater separators and drains. One option is presented as technically feasible (ensuring all drains are covered and routing the API separator vent gas to a control device for thermal combustion or oxidation), with potential 70% VOC control, but was not selected as RACT. One other area refinery (Chevron), however, operates a regenerative thermal oxidizer system in conjunction with covers and vent routing. Page 14 of the RACT Evaluation Report for Tesoro estimates VOC emission reductions as high as 11 tpy if a similar system were employed at Tesoro, but does not propose such a system, instead stating only that "further discussions on controlling wastewater VOC emissions need to be held." Since it is proven to be technically and economically feasible at another area refinery, why is it not proposed here? Please explain.

Response to H-79: Chevron's wastewater plant VOC emissions were significantly higher than those of the other three refineries. The Chevron refinery has had a well-established wastewater treatment system for longer than the other refineries. The system is also more extensive and was recently modernized. UDAQ believes that the estimates of potential VOC reductions from a wastewater system at the Big West Refinery to be overestimated, but has not yet had the opportunity to conduct on-site monitoring to determine a more appropriate value. This was stated clearly in the very next sentence on page 14 of the RACT Evaluation Report.

H-80 [Submitted by EPA Region 8]: There are a number of instances where new controls are identified as RACT in the RACT Evaluation Report, and are credited with emission reductions in the RACT Summary Table, but are not required in draft SIP subsection IX.H.12.r:

i) Page 5 of the RACT Evaluation Report identifies RACT for SO_2 at the FCCU as installation of WGS. The Report says a reduction of 585 tpy for SO_2 is expected. This expected reduction is also cited in the RACT Summary Table, to be achieved by 2019.

ii) Page 6 of the RACT Evaluation Report identifies RACT for NO_x at the FCCU as installation of WGS-LoTOx. The Report says a NO_x reduction of 106 tpy is expected. This expected reduction is also cited in the RACT Summary Table, to be achieved by 2019.

iii) Page 8 of the RACT Evaluation Report identifies RACT for NO_x at Process Heaters and Boilers as installation of ULNB on the heaters on the Ultraformer Furnace F -1. The Report says a NO_x reduction of 17 tpy is expected. This expected reduction is also cited in the RACT Summary Table, to be achieved by 2017. Draft SIP subsection IX.H.l2.r. specifies the calculations to be used for demonstrating compliance with sourcewide SO_2 and NO_x emission limits, but it is not apparent whether any of these calculations take into account any requirement to install and use new emission controls. Please explain. If Tesoro is being credited with emission reductions due to installation of new controls as RACT, then this needs to be reflected as proposed RACT in the SIP.

Response to H-80: The above cited RACT controls were taken into account in determination of both the annual and daily SIP emission Caps. However, individual control methodologies are not being included as specific requirements in the language of the SIP as this unnecessarily limits both the source and the agency from including better, higher efficiency controls, should such become available. By electing to require only a final emission limitation for these sources to maintain, UDAQ ensures that equivalent emission reductions are achieved without binding the source unnecessarily. See previous responses relating to individual emission controls, and the use of the RACT Summary Table, including H-4, 29, 52, and 53.

H-81 [Submitted by EPA]: Under "Source-wide $PM_{2.5}$," draft SIP subsection IX.H.12.r.i. reads, "Filterable PM2.s emissions shall be determined by applying various emission factors ... " This language is imprecise/vague. Please delete the word "various."

Response to H-81: UDAQ will remove the word "various" as requested.

H-82 [Submitted by EPA]: In the same paragraph, the language reads, "Unless otherwise specified by an Approval Order ... " This is not approvable language. EPA needs to be able to approve any revisions to the methods for determining compliance, unless the SIP establishes enforceable, replicable procedures for modifying the methods. For example, where a revision to an emission factor is established through a simple stack test, we have been willing to approve SIP language that describes the process. The process should include notice to us of the stack test date, results, and new emission factor.

Response to H-82: See response H-[~~5~~]107, regarding the language "Unless otherwise specified by an Approval Order."

H-83 [Submitted by EPA]: In the next paragraph, the language reads, "Daily gas consumption by all boilers and furnaces shall be measured by meters that can delineate the flow of gas to the indicated emission points." The phrase "indicated emission points" is undefined. The SIP language needs to specify the emission points that are covered.

Response to H-83: As discussed previously, the term "indicated emission points" was previously defined in the sentence as "all boilers and furnaces."

H-84 [Submitted by EPA]: In the next paragraph, the SIP language proposes to defer the establishment of a condensable ratio for FCCU wet gas scrubber stack and SRU/TGTU/TGI until "no later than January 1, 2019." At that time a new source-wide limit for $PM_{2.5}$ will be established in an AO. This is not approvable. There is no explanation why it would not be possible to establish the condensable ratio now, through testing, use of emission factors, or estimates. The SIP is supposed to evaluate RACT for condensable and filterable PM. The SIP cannot defer the establishment of limits. And the SIP must contain the RACT limits, not an AO.

Response to H-84: See response to H-61 regarding Setting Emission Factors by Performance Testing.

H-85 [Submitted by EPA]: Source-wide SO_2 provisions: There is no requirement for SO_2 CEMS or any other technique for accounting for SRU emissions. It is our understanding that the SRU at each refinery has an SO_2 CEMS, which we would expect to be used to account for a portion of source-wide SO_2 emissions. See, for example, draft SIP subsection IX.H.12.g.iii for Chevron, which requires use of SO_2 CEMS in determining SO_2 emissions from the SRU. Please explain why this is not accounted for at Tesoro.

Response to H-85: See response to H-64 regarding the use of SO_2 CEMs at the SRUs.

H-86 [Submitted by EPA]: The RACT Evaluation Report does not identify any level of control efficiency as RACT for SO_2 emissions from the SRU at Tesoro, nor does this appear in draft SIP subsections IX.H.11. or IX.H.12.r. We consider it essential to specify a level of control efficiency as RACT and would expect 95% or better control. Please supplement the TSD with a discussion of what level of control should be expected for the SRU at Tesoro and include that level of control in draft SIP subsection IX.H.11 or IX.H.12.r.

Response to H-86: See response to H-30 regarding the existing SRUs at each refinery, and the retention of SIP Section [~~IX.H.2.a.M.A.1~~]IX.A.2.1.M.A.1).

H-87 [Submitted by EPA]: Draft SIP subsection IX.H.12.r relies on NO_x CEMS at the FCCU wet gas scrubber, and on H_2S CEMS for plant fuel gas as an alternative to direct SO_2 measurement, to determine some of the emissions and emission factors, but this subsection of the draft SIP doesn't clearly require the operation of CEMS. This does not appear to be addressed by the General. Requirements for Petroleum Refineries at draft SIP subsection IX.H.11.g. Please see our related comment on IX.H.11.g.

Response to H-87: See response to H-13 on SIP Section IX.H.11.g as it relates to Section IX.H.11.f.

H-88 [Submitted by EPA]: There are no proposed requirements to report excess emissions. Please explain how this will be addressed.

Response to H-88: The reporting of excess emissions remains a requirement of UDAQ's existing breakdown rule and emissions inventory reporting requirements. These can be found at R307-107 and R307-150 respectively. Every approval order requires the permittee to comply with the requirements for breakdown reporting. No additional SIP reporting requirements are necessary.

H-89 [Submitted by Tesoro]: To be consistent with the language in "Limits on Refinery Fuel Gas" in H.11.g.ii and "FCCU PM Emissions" in H.11.g.i.B and to provide coverage for all applicable SO_2 emissions limits, Tesoro proposes this paragraph to be modified as follows:

> "SO_2 emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the emission limits in I, II above provided that during such periods the owner or operator implements good air pollution control practices to minimize SO_2 emissions."

Response to H-89: See previous response to H-5 regarding the inclusion of SSM Provisions.

H-90 [Submitted by Tesoro]: To provide flexibility if EPA approves additional cooling tower monitoring methods, Tesoro proposes the following modification to the paragraph:

> "... The owner or operator may elect to use another method other than the Modified El Paso Method if approved by the Director or EPA".

Response to H-90: See responses to H-21 and 29 regarding the use of alternative cooling tower monitoring methods.

H-91 [Submitted by Tesoro]: Tesoro proposes adding an additional paragraph to clarify the required monitoring frequency as follows:

> "Prior monitoring at equivalent leak definitions can be used to establish initial skip monitoring periods."

Response to H-91: See response to H-[~~22~~]49 regarding the inclusion of Sustainable Skip Period language to requirement H.11.g.iv.

H-92 [Submitted by Tesoro]: H.12.r.i. Source-wide $PM_{2.5}$ – Tesoro's maximum filterable $PM_{2.5}$ emissions to the atmosphere shall not exceed 0.42 tons per day and 110 tons per rolling 12-month period for the entire refinery.

Tesoro proposes a revision to condition H.12.r.i to make the language consistent with conditions H.12.r.ii and H.12.r.iii as well as other refinery $PM_{2.5}$ sections. The conditions do not contain the language "for the entire refinery".
~~"Tesoro 's maximum filterable~~ $PM_{2.5}$ emissions ~~to the atmosphere~~ from all combustion sources shall not exceed 0.42 tons per day (tpd) and 110 tons per rolling 12-month period ~~for the entire refinery"~~

Response to H-92: The intention of the language "for the entire refinery" was to clearly establish that the source-wide emission caps were all inclusive. Between the issuance of the 1994 PM_{10} SIP and the present, numerous permitting actions have taken place. These permitting actions have established the concept of SIP Cap and non-SIP Cap emission points, and made determination of a simple and clear emission inventory difficult. Some units' emissions are included for compliance determination under one set of rules but may not be included under another.
In order to simplify this potentially confusing set of circumstances, and to address all projection year SIP modeling scenarios, each of the refineries was modeled with the assumption that all emissions from that entire source would be capped at its respective "source-wide" SIP Cap. In order to assure that this assumption is maintained, these values need to remain as "limits" that apply to the entire source – regardless of any future permitting actions that may occur.
However, UDAQ recognizes that consistency between sources within the same emitting category is desirable, and that imposing consistent language will promote equity between those sources. Therefore, UDAQ will alter the language of H.12.r as follows:

> *By no later than January 1, 2019, combined emissions of filterable $PM_{2.5}$ shall not exceed 0.42 tons per day (tpd) and 110 tons per rolling 12-month period.*

This will match the language of paragraphs ii and iii for source-wide NO_x and SO_2 emissions.

H-93 [Submitted by Tesoro]: Consistent with the General Requirements of Section H.11, Tesoro proposes that the following language be added to this section:

> *"$PM_{2.5}$ emissions and opacity caused by or attributable to the Startup, Shutdown, or Malfunction shall not be used in determining compliance with the daily limits."*

Response to H-93: UDAQ disagrees with this comment. The emissions of $PM_{2.5}$ during periods of startup and shutdown are to be included with calculation of both daily and annual SIP Caps. When these Caps where used for determination of NAAQS attainment demonstration, no allowance for startup or shutdown exclusion was given. It was the intention that these emissions be included in the calculation of these totals whenever a SIP Cap was expressed on a daily or annual basis. Malfunction emissions are addressed by UDAQ's breakdown rule R307-107. As no opacity limits are listed in SIP Section IX.H.12.r, the remainder of this comment is not applicable and no changes are required.

H-94 [Submitted by Tesoro]: Tesoro operates a CO Boiler which requires daily periodic cleaning of the internal boiler surfaces to maintain heat transfer efficiency. Tesoro proposes that the following language be added to this section to exempt these short-term emissions from compliance requirements:

> *"$PM_{2.5}$ emissions and opacity caused by or attributable to Soot Blowing at the CO Boiler shall not be used in determining compliance with the daily limits nor the opacity limits established in R307-305-3."*

Response to H-94: UDAQ disagrees that a special provision for Soot Blowing opacity is required. R307-201-3(7) already provides an exemption for opacity events related to soot blowing, so long as adequate control technology and proper procedures are used. UDAQ also disagrees with not including these emissions in the $PM_{2.5}$ daily limits. As soot blowing is a routine event, as defined by the commenter's own use of the terms "daily" and "periodic" it does not qualify as startup, shutdown or malfunction. The purpose of a $PM_{2.5}$ daily limit is to include all emissions from the refinery that occur within at 24-hour period that are the result of normal operations.

As these emissions can reasonably be expected to occur on any given day, including those wintertime inversion days for which the SIP controls are specifically designed; and that the commenter has expressed no technological limitations or difficulties with calculating or measuring these emissions, these emissions shall continue to be included.

H-95 [Submitted by Tesoro]: Comment: *H. 12. r. i. (7th Paragraph)*
By no later than January 1, 2019, Tesoro shall conduct stack testing to establish the ratio of condensable $PM_{2.5}$ from the FCCU wet gas scrubber stack and SRU/TGTU/TGL

Tesoro requests that the requirement to test the SRU/TGTU/TGI be deleted. This requirement is only included in Tesoro and Chevron's source specific conditions. Conducting the $PM_{2.5}$ test at the SRU Incinerator would pose significant technical challenges due to the incinerator stack gas conditions and may not result in accurate results. The high temperature of the incinerator exhaust requires a refractory-lined stack, which may be damaged by installation of the large ports necessary to complete Method 202 condensable PM stack testing. Additionally, results of the testing may be biased high as a result of SO_2 present in the stack gas, which has the potential to form condensable PM in the sampling equipment. The condensable PM emissions from the SRU/TGTU/TGI are expected to be relatively small compared to other sources at Tesoro and in Salt Lake County, which limits the benefits of quantifying condensable PM emissions from this source.

Response to H-95: UDAQ agrees with this comment. Given the technological limitations associated with testing at the SRU/TGTU/TGI stack, no condensable PM testing shall be required. Consequently, this requirement shall be removed, and only the stack testing requirement for the FCCU shall remain in this paragraph. The ratio for the SRU/TGTU/TGI shall be determined from the latest version of AP-42.

H-96 [Submitted by Tesoro]: Comment: *H..12. r. ii. Source-wide NO_x*
Combined emissions of NO_x shall not exceed 0.82 tons per day (tpd) and 300 tons per rolling 12-month period.

Tesoro requests the daily NO_x limit of 0.82 tpd be changed to the current limit of 1.988 tpd. A daily limit of 0.82 tpd is a reduction of 60% from Tesoro's allowable daily limit. The RACT Evaluation Report identified annual NO_x emission reductions which Tesoro can achieve. However a daily limit of 0.82 tons per day would require significant more reductions than what was established as RACT. The RACT Evaluation Report did not focus on reductions in short-term emissions. Daily emissions are more variable than annual emissions due to changes in utilization inherent to operating a refinery. The current SIP limits (1.988 tpd, 598 tons per year) were developed to reflect this relationship between daily and annual emissions.

Tesoro requests that the annual limit of 300 tons per rolling 12-month period be changed to the limit of 475 tons per rolling 12-month period. A NO_x reduction of 106 tpy from the FCU and 17 tpy from the F-I Heaters was identified as RACT in the RACT Evaluation Report. No further NO_x reductions were identified and therefore should not be applied to the permitted limit of 598 tons per year. Basing the revised annual emission limit on 2008 actual emissions rather than allowable emissions does not adequately allow for normal business growth.

Response to H-95: We agree with this comment. After review of the information submitted by the commenter and comparison with the technical support documentation, UDAQ agrees that errors was made with establishing annual emission limits. While RACT reductions were applied to the 2008 true-up inventory as was performed for all other sources, two calculation errors led to an incorrect annual limit. The first was a math error which led to an incorrect amount being subtracted from the inventory, while the second was the failure to apply any operational buffer. UDAQ agrees that this places the Tesoro Refinery in a position of potential compliance issues, as well as at an operational disadvantage when compared with its direct competitors. The NAAQS attainment demonstration model was rerun with these values included and no change in the final predicted concentration was shown.

The calculation methodology, as requested by Tesoro, is acceptable to UDAQ.

H-96 [Submitted by Tesoro]: The limits as currently written do not indicate an effective date, and are based upon expected actual emissions following installation of RACT. Tesoro proposes the following language be added to this section to allow time for installation of control equipment:

"By no later than January 1, 2019, combined emissions of NO_x shall not exceed 1.988 tons per day (tpd) and 475 tons per rolling 12-month period."

Response to H-96: We agree with this comment. UDAQ recognizes that equipment such as the wet gas scrubber and low-TOx unit represents a significant capital investment with associated significant lead times, engineering, construction, startup, shakedown and testing involved. Therefore, the date suggested by Tesoro is acceptable to UDAQ based on the requirement to install and test the new control equipment.

H-97 [Submitted by Tesoro]: Consistent with the General Requirements of Section H.11,Tesoro proposes the following language be added to this section:

"NO_x emissions caused by or attributable to the Startup, Shutdown, or Malfunction shall not be used in determining compliance with the daily limits."

Response to H-97: We disagree with this comment. The emissions of NO_x during periods of startup and shutdown are to be included with calculation of both daily and annual SIP Caps. When these Caps where used for determination of NAAQS attainment demonstration, no allowance for startup or shutdown exclusion was given. It was the intention that these emissions be included in the calculation of these totals whenever a SIP Cap was expressed on a daily or annual basis. Malfunction emissions are addressed by UDAQ's breakdown rule R307-107.

H-98 [Tesoro]: Comment: *H. r. iii. Source-wide SO_2*
Combined emissions of SO_2 shall not exceed 0.82 tons per day (tpd) and 300 tons per rolling 12-month period

Tesoro requests the daily SO_2 limit of 0.82 tpd be changed to 3.1 tpd. This equates to a reduction in the daily limit of SO_2 emissions of 48% compared to the current limit of 4.374 tpd during March 1 - October 31. A limit of 3.1 tpd also corresponds to the RACT Evaluation Report which included the following:

NSPS Subpart Ja limit: 3 hour average limit of 162 ppm H_2S in the refinery fuel gas
NSPS Subpart Ja limit: 7 day average of 50 ppm @0% O_2 following the installation of a Wet Gas Scrubber at the FCCU
Flare gas recovery and flared gas that meets 162 ppm H_2S
Current SRU limit of 1.68 tpd following the installation of a TGTU

Tesoro accepts the annual limit of 300 tpy. This reduction is equivalent to an 82% reduction from the permitted limit of 1637 tpy SO_2.

Response to H-98: We disagree with this comment. The value requested by Tesoro allows for adequate operational flexibility over the short term, while preserving the individual RACT requirements outlined in the TSD. The setting of an operational limit might seem contrary to the concept of modeling a projection of actual emissions; however, UDAQ notes that few sources operate continuously at or near their emission limits. Temporary, short-term, spikes in emissions which can be accommodated by an operational daily limit allow a source to remain in compliance while maintaining an overall lower emission value. A review of the values used in the attainment demonstration model shows that a 3.1tpd SO2 emission rate can be accommodated.

H-99 [Tesoro]: The limits as currently written do not indicate an effective date, and are based upon expected actual emissions following installation of RACT. Tesoro proposes the following language be added to this section to allow time for installation of control equipment:

"By no later than January 1, 2019, combined emissions of SO_2 shall not exceed 3.1 tons per day (tpd) and 300 tons per rolling 12-month period."

Response to H-99: We agree with this comment. The date suggested by Tesoro is acceptable to UDAQ based on the requirement to install and test new control equipment, such as the wet gas scrubber, and TGTU.

H-100 [Tesoro]: Consistent with the General Requirements of Section H.11, Tesoro proposes the following language be added to this section:

"SO_2 emissions caused by or attributable to the Startup, Shutdown, or Malfunction shall not be used in determining compliance with the daily limits."

Response to H-100: We disagree with this comment. The emissions of SO_2 during periods of startup and shutdown are to be included with calculation of both daily and annual SIP Caps. When these Caps where used for determination of NAAQS attainment demonstration, no allowance for startup or shutdown exclusion was given. It was the intention that these emissions be included in the calculation of these totals whenever a SIP Cap was expressed on a daily or annual basis. Malfunction emissions are addressed by UDAQ's breakdown rule R307-107.

BIG WEST OIL REFINERY (a.k.a. Flying J)

H-101 [EPA]: The RACT Summary Table indicates that ultra low NO_x burners (ULNB) will be installed by 2017, and that a flue gas filter for PM control, $deSO_x$ catalyst for SO_2 control, and a redundant scrubber for SO_2 control will all be installed by 2019. Please explain why an earlier date would not be achievable.

Response to H-101: These items represent large capital investments with significant lead times, engineering, construction, startup, shakedown and testing involved. This date was reached through negotiation with the source based on the source's expected construction schedule after consideration of each factor.

H-102 [EPA]: There are a number of instances where new controls are identified as RACT in the RACT Evaluation Report, and are credited with emission reductions in the RACT Summary Table, but are not required in draft SIP subsection IX.H.12.b:

i) Page 5 of the RACT Evaluation Report identifies RACT for SO_2 at the FCCU as use of $deSO_x$ catalyst. The Report says an SO_2 reduction of 125 tpy is expected. This expected reduction is also cited in the RACT Summary Table, to be achieved by 2019.

ii) Page 8 of the RACT Evaluation Report identifies RACT for NO_x at Process Heaters and Boilers as retrofitting the three boilers and replacing the unifier charge heater with ULNB capable of achieving a NO_x emission rate of 0.035 lb/MMBtu. The Report says a NO_x reduction of 30 tpy is expected. This expected reduction is also cited in the RACT Summary Table, to be achieved by 2017.

iii) Page 9 of the RACT Evaluation Report identifies RACT for SO_2 at the SRU as installation of a redundant SO_2 caustic scrubbing system, to be operated in the event of SRU malfunction or planned outage. The Report says an SO_2 reduction of 50 tpy is expected. This expected reduction is also cited in the RACT Summary Table, to be achieved by 2019. Draft SIP subsection IX.H.l2.b specifies the calculations to be used for demonstrating compliance with sourcewide SO_2 and NO_x emission limits, but it is not apparent whether any of these calculations take into account any requirement to install and use new emission controls. Please explain. If Big West Oil is being credited with emission reduction due to installation of new controls as RACT, then this needs to be reflected as proposed RACT in the SIP.

Response to H-102: Each of the above cited RACT controls was taken into account in determination of both the annual and daily SIP emission Caps. These specific controls were also chosen by the source as a method for reaching the specific emission limitations listed in Section IX.H.11.g General Refinery Requirements. However, individual control methodologies are not being included as specific requirements in the language of the SIP as this unnecessarily limits both the source and the agency from including better, higher efficiency controls, should such become available. It would also prevent a source from applying additional "beyond RACT" controls that would require discontinuation of a listed control option without requiring a SIP change – as the source would then be operating in violation of the SIP for failure to include the less efficient option.

Such an example would be requiring a source to include $deNO_x$ catalyst at the FCCU. The source then installs a low-TOx unit on its wet gas scrubber rendering the use of $deNO_x$ catalyst redundant and wasteful. However, failure to add the $deNO_x$ would constitute a SIP violation unless the SIP is changed – a lengthy, arduous, and difficult process occupying a minimum of several months' time.

Instead, UDAQ has opted to include the emission limitation (such as those in Section IX.H.11.g) and an overall emission reduction (the daily and annual SIP Caps) and allow the individual sources to meet or improve upon those values. UDAQ sees no need to punish innovation and ingenuity with overly restrictive and unnecessary SIP restrictions.

H-103 [EPA]: Page 12 of the RACT Evaluation Report proposes no changes to existing wastewater operations as VOC RACT for wastewater separators and drains. One option is presented as technically feasible (ensuring all drains are covered and routing the API separator vent gas to a control device for thermal combustion or oxidation), with potential 70% VOC control, but was not selected as RACT. One other area refinery (Chevron), however, operates a regenerative thermal oxidizer system in conjunction with covers and vent routing. Page 12 of the RACT Evaluation Report for Big West Oil estimates VOC emission reductions as high as 38 tpy if a similar system were employed at Big West, but does not propose such a system, instead stating only that "further discussions on controlling wastewater VOC emissions need to be held." Since it is proven to be technically and economically feasible at another area refinery, why is it not proposed here? Please explain.

Response to H-103: Chevron's wastewater plant VOC emissions were significantly higher than those of the other three refineries. The Chevron refinery has had a well-established wastewater treatment system for longer than the other refineries. The system is also more extensive and was recently modernized. UDAQ believes that the estimates of potential VOC reductions from a wastewater system at the Big West Refinery to be overestimated, but has not yet had the opportunity to conduct on-site monitoring to determine a more appropriate value. This was stated clearly in the very next sentence on page 12 of the RACT Evaluation Report.

H-104 [EPA]: Under "Source-wide $PM_{2.5}$," draft SIP subsection IX.H.12.b.i. reads, "Following installation of the Flue Gas Blow Back Filter (FGF)," but does not specify a deadline for installation of the FGF. This is not approvable because the limits key off of installation of the FGF.

Response to H-104: UDAQ agrees with this comment. There is a missing phrase from this first sentence which should have included the installation date of the FGF. Following changes to make the language of this section consistent with that of the other refineries, the sentence should now read as follows:

> *Following installation of the Flue Gas Blow Back Filter (FGF), but no later than January 1, 2019, combined emissions of filterable PM2.5 shall not exceed 0.18 tons per day and 45 tons per rolling 12-month period.*

This allows the source the opportunity to install, test and operate the equipment by an earlier date, but still establishes a final date by which the SIP Caps take effect. UDAQ apologizes for the missing language.

H-105 [EPA]: Same paragraph, the SIP language proposes to defer the establishment of a condensable ratio for the Catalyst Regeneration System until "no later than January 1, 2019." At that time a new source-wide limit will be established in an AO. This is not approvable. There is no explanation why it would not be possible to establish the condensable ratio now, through testing, use of emission factors, or estimates. The SIP is supposed to evaluate RACT for condensable and filterable PM. The SIP cannot defer the establishment of limits. And the SIP must contain the RACT limits, not an AO.

Response to H-105: As EPA has commented previously, the "EPA Clean Air Particulate Implementation Rule (FR 72, 20586)" has been remanded, and the March 2, 2012 guidance titled "Implementation Guidance for the 2006 24-Hour Fine Particulate (PM2 5) National Ambient Air Quality Standards (NAAQS)" has been withdrawn. Additionally, 40 CFR 51.1000, Subpart Z- Provisions for Implementation of PM2.5 National Ambient Air Quality Standards should not be used because the information in the CFR comes from the 2007 Clean Air Particulate Implementation Rule that was remanded. …note that it's 51.1002 (c) (from subpart Z) that said "States must establish such limits taking into consideration the condensable fraction of direct $PM_{2.5}$ emissions." Based on these statements, UDAQ does not agree that setting a limit on the condensable fraction of $PM_{2.5}$ emissions without adequate testing data, especially as it pertains to setting the condensable/filterable ratio on new and previously unseen equipment and processes such as Big West Refinery's FGF system.

H-106 [EPA]: In the next paragraph, the language reads, "Filterable $PM_{2.5}$ emissions shall be determined by applying various emission factors ... " This language is imprecise/vague. Please delete the word "various".

Response to H-106: Although the word "various" is used as nothing more than a descriptive term to refer to the multiple and different emission factors which are then described and discussed in subsequent paragraphs, UDAQ is willing to remove the word. However, as the following comment also seeks to make an adjustment to this same paragraph, please see the response to that comment for the final version of the language to this paragraph.

H-107 [EPA]: In the same paragraph, the language reads, "Unless otherwise specified by an Approval Order ... " This is not approvable language. EPA needs to be able to approve any revisions to the methods for determining compliance, unless the SIP establishes enforceable, replicable procedures for modifying the methods. For example, where a revision to an emission factor is established through a simple stack test, we have been willing to approve SIP language that describes the process. The process should include notice to us of the stack test date, results, and new emission factor.

Response to H-107: UDAQ has adjusted the language of this paragraph based on this and the previous comment. The paragraph will now read as follows:

> *$PM_{2.5}$ emissions shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Unless adjusted by performance testing as discussed above, the default emission factors to be used are as follows:*

The remaining paragraphs which include the specific emission factors and calculation methodologies will remain unaltered. Similar changes will be included appropriately for NO_x and SO_2 and in the equivalent sections of IX.H.12.g, k and r.

H-108 [EPA]: In the next paragraph, the language reads, "Daily gas consumption by all boilers and furnaces shall be measured by meters that can delineate the flow of gas to the indicated emission points." The phrase "indicated emission points" is undefined. The SIP language needs to specify the emission points that are covered.

Response to H-108: In this case, "indicated emission points" was previously defined in the sentence as "all boilers and furnaces." The meters in question are measuring the flow of gas to the boilers and furnaces, such that a daily gas consumption value can be obtained.

H-109 [EPA]: Source-wide NO_x provisions: Same issues regarding use of phrase "various emission factors," AO overriding the SIP for establishment of emission factors, AO as the future location for emission factors should "future information reveal that there is a difference in the emission factors for natural gas and plant gas," and use of the phrase "indicated emission points."

Response to H-109: See responses to comments H-39, 60, 81, 106 regarding the use of the term "various," H-40 regarding the use of AOs for establishment of emission factors, and H-41regarding the use of the phrase "indicated emission points."

H-110 [EPA]: Same issue regarding use of the phrase "various emission factors." Also, the phrase "by whatever meters are necessary" is imprecise/vague. Also, there is no requirement for SO_2 CEMS or any other technique for accounting for SRU emissions. It is our understanding that the SRU at each refinery has an SO_2 CEMS, which we would expect to be used to account for a portion of source-wide SO_2 emissions. See, for example, SIP subsection IX.H.12.g.iii for Chevron, which requires use of SO_2 CEM in determining SO_2 emissions from the SRU. Please explain why this is not accounted for at Big West.

Response to H-110: See responses to H-81 and 106 regarding the use of the term "various," and H-64 regarding the requirement for using SO_2 CEMs. The phrase "by whatever meters are necessary" shall be altered to be more precise. The sentence in question shall now read as follows:

"Daily plant gas consumption at the furnaces and boilers shall be measured by flow meters".

H-111 [EPA]: The RACT Evaluation Report does not identify any level of control efficiency as RACT for SO_2 emissions from the SRU at Big West Oil, nor does this appear in draft SIP subsections IX.H.11. or IX.H.12.b. We consider it essential to specify a level of control efficiency as RACT and would expect 95% or better control. Please supplement the TSD with a discussion of what level of control should be expected for the SRU at Big West Oil and include that level of control in draft SIP subsection IX.H.11 or IX.H.l2.b.

Response to H-111: See response to H-30 regarding the existing SRUs at each refinery, and the retention of SIP Section [~~IX.H.2.a.M.A.1~~]IX.A.2.1.M.A.1).

H-112 [EPA]: Draft SIP subsection IX.H.12.b relies on NO_x and H_2S CEMS to determine some of the emissions and emission factors, but this subsection of the draft SIP doesn't clearly require the operation of CEMS. This does not appear to be addressed by the General Requirements for Petroleum Refineries at draft SIP subsection IX.H.l1.g. Please see our related comment on IX.H.11 .g.

Response to H-112: See response to H-13 on SIP Section IX.H.11.g as it relates to Section IX.H.11.f.

H-113 [EPA]: There are no proposed requirements to report excess emissions. Please explain how this will be addressed.

Response to H-113: The reporting of excess emissions remains a requirement of UDAQ's existing breakdown rule and emissions inventory reporting requirements. These can be found at R307-107 and R307-150 respectively. Every approval order requires the permittee to comply with the requirements for breakdown reporting. No additional SIP reporting requirements are necessary.

H-114 [WRA]: The Emission Limits include source-wide $PM_{2.5}$, NOX and SO_2 emission limits for the Big West Oil Refinery. A source-wide emission limit should also be established for VOC at the refinery. Individual emission limits must be set at the major units or process points at the refinery, such as the FCCU. Such an approach is mandated as RACT – which is required for each emission unit – and is also required under Title V. Moreover, without limits on each emission unit, it is difficult, if not impossible, to compare emission limitations at this facility with other facilities in order to access whether RACT has been met.

Response to H-114: This is a multi-part comment. With respect to setting a source-wide emission limit for VOC at the refinery, UDAQ disagrees with this comment. The largest contributor to VOC emissions from any refinery are fugitives from leaking components, tank working losses, and similar items. While emissions from these components can be estimated, and with a fairly high degree of confidence, such estimates are still only estimates. They are based on leak detection; estimates of tank working losses based on ambient temperature, tank color, and material being stored; detection of VOCs in cooling water by random sampling and estimates of time the heat exchanger has allowed fluid transfer. The purpose of establishing RACT in all of these cases is to lower the total amount of VOCs being released into the atmosphere. This is achieved by implementing the best work practice standards, requiring each source to prepare a plan demonstrating how those work practices will be implemented, and then enforcing against said plan. The implementation of a limit based entirely on estimated emissions would add no value in achieving the goal as outlined above.

With respect to setting individual emission limits for major units or process points, UDAQ disagrees with this comment as well. There are two different approaches that can be taken with respect to RACT: a source-wide approach, or a major emitting unit approach. Both options were discussed between UDAQ and EPA Region 8 during development of the $PM_{2.5}$ SIP. The source-wide approach involves setting a single emission "cap" for each pollutant, where possible or practical. This approach is most useful for large complex industrial sources with multiple emission points, where setting individual emission limits on each emission unit would make the SIP document unwieldy and overly complicated. The alternate method is the major emitting unit approach, which was suggested for use by EPA Region 8 specifically for those sources where the majority of the emissions comes from just a few emitting units. Imposing both individual limits and source-wide limits simultaneously negates these concepts. *See also* previous responses regarding individual emission controls, and the use of the RACT Summary Table (H-4 and 29).

H-115 [WRA]: The Emission Limits reflect installation in 2019 of a flue gas filter and deSOX catalyst to control emissions from the FCCU. At the very least, these controls must be installed considerably sooner than 2019. The RACT/BACT/LAER clearinghouse indicates that RACT requires tighter controls, including WGS and newer, more efficient ESPs and baghouses. Moreover, as Techlaw states, the single WGS system would yield both PM and SO_2 emission reductions and should be evaluated as such. At the same time, SCR should be considered for Big West Oil based on the low emission limits that have been achieved at FCCUs around the country operating with SCRs. Apparently, Big West will achieve a NOX emission rate of 0.035 lbs/MMBtu or less as part of its consent decree. Because these reductions will be relied on to achieve attainment with the $PM_{2.5}$ NAAQS, this emission limitation must be included in the

SIP. Also, a NOX limit of 0.0061 lb/MMBtu, which can be achieved using ultra low NOX burners, SCR or LTO, more accurately reflects RACT. Beginning in 2019, Big West will use a redundant scrubber for SO_2 control at the SRU. At a minimum, installation of this control should be required immediately.

Response to H-115: With respect to requiring installation of control equipment at an earlier date; these items represent large capital investments with significant lead times, engineering, construction, startup, shakedown and testing involved. This date was reached through negotiation with the source based on the source's expected construction schedule after consideration of each factor.

With respect to comments on RACT, UDAQ thanks the commenter for the comment. While final RACT determinations were made at the December 4, 2013 meeting of the Utah Air Quality Board when it voted to accept SIP Subsection IX.A.21: Control Measures for Area and Point Sources, Fine Particulate Matter, $PM_{2.5}$ SIP for the Salt Lake, UT Nonattainment Area and SIP Subsection IX.A.22: Control Measures for Area and Point Sources, Fine Particulate Matter, $PM_{2.5}$ SIP for the Provo, UT Nonattainment Area, UDAQ anticipates the need to submit a new BACT/RACT analysis as part of a Subpart 4 Serious $PM_{2.5}$ Nonattainment Area SIP in the near future, and would invite the commenter to resubmit this comment at that time

SILVER EAGLE

H-116 [Silver Eagle]: Silver Eagle believes General Refinery Requirement H.11.g.v Paragraph B, requiring all refineries to install flare gas recovery exceeds technical and economic basis for RACT. Silver Eagle operates a small niche refinery that generates very little recoverable flare gas. A recent evaluation of the annualized cost to install, operate and maintain a flare gas recovery system at the Silver Eagle facility shows such a project to cost $120,526/ton of combined VOC, PM-10 and PM-2.5 emissions reduced. Silver Eagle believes this cost is not economically feasible and is therefore not RACT.

Furthermore, On August 7, 2013, in a PM-2.5 SIP presentation by Marty Gray (DAQ Major New Source Review Section Manager) titled, "$PM_{2.5}$ State Implementation Plan Reasonable Available Control Technology Process", it was stated the Silver Eagle would become a minor synthetic source and would therefore not be subject to RACT (see attached pages from this presentation). Silver Eagle anticipates it will soon become a synthetic minor source. As such, the potential RACT requirement to install mandatory flare gas recovery for Silver Eagle's small refinery would not apply.

Response to H-116: The comment continues with additional reference and citation from NSPS Subpart Ja and UDAQ's own General Refinery RACT Evaluation Report. At the time of release to public comment it was the intention that all refinery hydrocarbon flares would be subject to the requirements of IX.H.11.g.v.B. However, UDAQ agrees with Silver Eagle's argument that, as a synthetic minor source, it is not subject to the provisions of IX.H.11.g.v.B. This is best demonstrated by the first paragraph of Section 2.7 of the RACT Evaluation Report which states:

DAQ's contractor proposed that each of the refineries be subject to 40 CFR 60 Subpart Ja for each hydrocarbon flare at their facilities. This was a significant finding. There are four major source refineries within the $PM_{2.5}$ non-attainment area

This shows that during its own evaluation UDAQ was reviewing only major source refineries and did not evaluate the emissions from Silver Eagle. A review of the total 2008 "true-up" emissions from both the North and South flares at the Silver Eagle Refinery shows less than 2 tons per year of actual emissions from all pollutants combined – both $PM_{2.5}$ and precursor emissions, as well as CO and ammonia.

Given the economic infeasibility of achieving measurable NAAQS attainment benefit, and the arguments expressed above, UDAQ agrees that IX.H.11.g.v.B does not apply to the Silver Eagle Refinery. Appropriate adjustments in the language of IX.H.11.g.v.B will be made so that it shall only apply to major source refineries.

H-117 [Silver Eagle]: Silver Eagle recommends requiring each refinery to meet the requirements of NSPS Ja as stated in H.11.g.v. paragraph A, and remove paragraph B from the SIP.

Response to H-117: Except as otherwise outlined in UDAQ's response to the previous comment regarding the applicability of paragraph B only to major source refineries, UDAQ disagrees with this comment. Flare gas recovery was determined to be RACT as approved by the Utah Air Quality Board on December 4, 2013.

BOUNTIFUL CITY LIGHTS AND POWER: POWER PLANT

H-118 [EPA]: Comments on Gas Turbine #1 - i) The table provided to us on October 31, 2013 indicates that NAAQS attainment modeling was based on projected actual emissions for existing turbine GT #1 and for the existing internal combustion engine #8. Page 2 of the RACT Evaluation Report indicates that 2008 actual emissions for GT # 1 were less than 1 ton/year for each pollutant of interest ($PM_{2.5}$, NO_x, SO_2 and VOC). We expect that the projected actual emissions would be only slightly higher. However, draft SIP subsection IX.H.12.c indicates that the proposed RACT allowable for GT #1 is 0.6 grams NO_x per kilowatt-hour. Since GT #1 is rated at 5.3 MW, the proposed RACT allowable is equivalent to allowable NO_x emissions of 7 lb/hr, or 30.7 tons/year. The RACT Evaluation Report indicates that the PTE for this turbine is 13.3 tons/year for NO_x. Please explain how the proposed RACT allowable could equate to a tons/year figure that is substantially more than the PTE. Also, please explain how the projected actual emissions could be a valid basis for modeling when the proposed allowable emissions are at least 30 times higher (30.7 tons/year allowed versus less than 1 ton/year actual).

Response to H-118: The emission limit established for this turbine was derived from AO DAQE-101200003-13. The limit, as established in that AO did not include an exemption for startup or shutdown periods. Emissions of NO_x during these periods can be significantly higher than during steady-state operation, as EPA is well aware. As this turbine is not equipped with any add-on controls for NO_x emissions (*see* RACT analysis for details on infeasibility of installing add-on controls), no separate limit for steady-state operation was established. Continuing to demonstrate proper operation and maintenance through compliance with this limit demonstrates RACT. The PTE calculation is based on historical measurements of actual emissions during steady-state operation, and maximum potential operation. UDAQ recognizes that it is unrealistic to assume that the turbine would remain in operation in a startup configuration continuously; therefore, PTE is not based on a strict emission limit times MW rating.

H-119 [EPA]: Comments on Gas Turbines #2 and #3:

i) The table provided to us on October 31, 2013 indicates that modeling was based on 90% of PTE for the two new turbines. Page 2 of the RACT Evaluation Report indicates that the PTE for NO_x for each new turbine is 39.65 tons/year. The proposed RACT allowable in draft SIP subsection IX.H.l2.c. is 15 ppm for NO_x at each turbine. Please explain what the equivalent allowable would be in terms of tons/year and how that compares to the PTE figure of 39.65 tons/year. Our objective here is to see if there is a substantial difference between the proposed allowable emissions and the emissions used for modeling.

Response to H-119: Similar to GT #1 (*see* previous response), the limits for GT #2 and #3 were derived from AO DAQE-101200003-13. In that AO, an additional 7.5 lb/hr limit is included, which assumes steady-state operation. With an adjustment to include the emissions from startup and shutdown, this equates to approximately 44.06 tons/year. Taking 90% of this PTE value is where the 39.65 tons/year is derived. The 7.5 lb/hr limit is not included in the SIP, as UDAQ has elected to include the technology-based 15 ppm limit as appropriate for RACT.

H-120 [EPA]: Comments on Dual Fuel IC Engine #8:

i) Draft SIP subsection IX.H.12.c does not include any proposed emission limits or operational restrictions as RACT for IC Engine #8. Page 11 of the RACT Evaluation Report identifies Good

Combustion Practices as RACT for NO_x at this engine. The current title V permit specifies a NO_x emission limit for this engine in grams per horsepower-hour, and requires testing for compliance after every 800 operating hours, or at least once every 24 months. Please explain why this emission limit was not included in subsection IX.H.12.c. as proposed NO_x RACT for this engine.

Response to H-120: In the BCLP RACT Evaluation Report, Page 7, UDAQ identified that this engine has a remaining life expectancy of approximately nine (9) years, and for NO_x emissions both the baseline actual and PTE were established as 8.57 tons/year. While this is based on the current AO (DAQE-101200003-13), UDAQ sees no benefit in including a source of this small emission size and limited impact in the SIP, especially given that the RACT analysis resulted in no changes to the current established emission limitations.

CONSTEALLATION ENERGY RESOURCE (CER GENERATION II, LLC), West Valley Power Plant

H-121 [EPA]: The table provided to us on October 31, 2013 indicates that modeling was based on projected actual emissions. However, page 1 of the RACT Evaluation Report indicates that "Rather than using the actual emissions from 2008, potential to emit values (permitted emissions) are used for establishment of a baseline for RACT evaluation." This leaves it somewhat unclear whether PTE might have been used for modeling, rather than projected actual emissions. Please explain. Our objective here is to see if there is a substantial difference between the proposed RACT allowable and the emissions used for modeling.

Response to H-121: For this source, which already includes substantial control technology (*see* CER Generation II RACT Evaluation Report), performing a RACT analysis on the basis of the 2008 baseline actual emissions would not have yielded a useful analysis for $PM_{2.5}$ or VOC emissions as the emissions for these two pollutants on a turbine-by-turbine basis fell below the cut-off levels established by UDAQ (emissions of 5 tons/year or above by pollutant by emission unit). Instead, the PTE values were used to establish this analysis. A quick review of the TSD modeling spreadsheets shows that the same value of 37.99 tons NO_x/year was used for modeling purposes as well.

H-122 [EPA]: Page 4 of the RACT Evaluation Report identifies RACT for VOC as retention of the existing oxidation catalyst systems, and indicates that those systems can probably be expected to keep VOC emissions down to about 10 ppm. However, draft SIP subsection IX.H.12.d does not include any proposed emission limit or required controls for VOC. Please explain why this is not included.

Response to H-122: With total expected VOC emissions of less than 5 tons per year, UDAQ sees no benefit for specifically listing an emission limit for this pollutant. The existing systems have established monitoring, recordkeeping and reporting requirements for CO emissions that are included as a part of the source's Title V Operating Permit (Permit Number 3500527002, dated June 15, 2009). These requirements are sufficient to demonstrate proper operation and maintenance of the control system.

H-123 [EPA]: Draft SIP subsection IX.H.12.d. proposes RACT allowables for the turbines on a 30-day rolling average. Please explain how 30-day rolling averages can represent RACT in a plan that is intended to attain a 24-hour NAAQS.

Response to H-123: These are natural gas-fired turbines fired exclusively on pipeline quality natural gas. The units have well-established and well-understood emission rates that do not vary over the short-term. The units are equipped with CEMs for addressing emission trends and for monitoring against unavoidable breakdowns. In general, however, these emission units are not expected to have emissions whose rates vary significantly enough that a shorter averaging period is required. A 30-day rolling average is established primarily for SCR/oxy-cat catalyst regeneration and/or replacement tracking, and is a standard averaging period for units of this type.

H-124 [EPA]: Draft SIP subsection IX.H.12.d relies on CEMS to determine emissions but doesn't clearly require the operation of CEMS. This does not appear to be addressed by the General Requirements at draft SIP subsection IX.H.11 . Requirements to operate and maintain CEMS should be included in IX.H.11 or in IX.H.12.d.

Response to H-124: The requirements for CEM operation are found in SIP Section IX.H.11.f.

H-125 [EPA]: There are no proposed requirements to report excess emissions. Please explain how this will be addressed.

Response to H-125: The reporting of excess emissions remains a requirement of UDAQ's existing breakdown rule and emissions inventory reporting requirements. These can be found at R307-107 and R307-150 respectively. Every approval order requires the permittee to comply with the requirements for breakdown reporting. No additional SIP reporting requirements are necessary.

PACIFICORP GADSBY

H-126 [EPA]: Page 9 of the RACT Evaluation Report says, "The summary of all the above RACT evaluations is that PacifiCorp will extend the SCR catalyst beds on each of the three combustion turbines at the Gadsby facility. This will increase the amount of catalyst and slightly reduce NO_x emissions. Total NO_x is expected to drop by 10.7 tons of actual emissions by the 2017 projection year." The RACT Summary Table indicates that Gadsby is being credited with a 10.7 tpy NO_x emission reduction due to expansion of the SCR catalyst beds. However, draft SIP subsection IX.H.12.q. does not reflect this. The proposed RACT emission limits for NO_x for the turbines (5 ppmdv and 22.2lblhr at each turbine) are the emission limits that are already in effect. There is no requirement to expand the SCR catalyst beds. If Gadsby is being credited with a NO_x emission reduction resulting from expansion of the catalyst beds, then this needs to be reflected as proposed RACT in the SIP.

Response to H-126: UDAQ agrees with this comment. Although the overall emission limits for each turbine were not being changed, there was a credited emission decrease from expansion of the catalyst beds which is not reflected by any language found in SIP Section IX.H.12.q. UDAQ will include a new requirement IX.H.12.q.iv.D which will read as follows:

D. The owner/operator shall expand the catalyst beds to achieve additional NO_x control on Natural Gas-fired Simple Cycle Turbine Units (Units #4, #5 and #6) by no later than January 1, 2017.

H-127 [EPA]: The RACT Summary Table indicates that SCR catalyst beds will be expanded for NO_x control at the natural gas fired turbines by 2017. Please explain why an earlier date would not be achievable.

Response to H-127: The change in the SCR catalyst beds will require temporary shutdowns of the existing SCR units on each combustion turbine to allow for additional catalyst placement and ammonia injection. Scheduling these shutdowns, along with the resulting startup, shakedown and testing period which follows were considered in determining the compliance date.

H-128 [EPA]: Please explain how the emissions used for NAAQS attainment modeling compare to the emissions that are proposed to be allowed, on a plantwide daily basis. The table provided to us on October 31, 2013 indicates that projected actual emissions were used as the basis for modeled emissions. Pages 2 and 6 of the RACT Evaluation Report indicate that actual NO_x emissions in 2008 were 154.2 tons at the boilers and 29.6 tons at the combustion turbines, for a plantwide total of 183.8 tons. We expect that projected actuals would be slightly higher. However, we are unable to determine what the proposed RACT allowables equate to in tons per year, for the overall plant. Draft SIP subsection IX.H.12.q. proposes NO_x emission limits of 336 ppmdv at each of the three boilers and 22.2 lb/hr for the three turbines combined. The equivalent annual allowable for the turbines is 97.2 tons, which is 3.3 times as much as the 2008 actual emissions. Please explain what the equivalent annual allowable is for the boilers. Our objective here is to see if there is a substantial difference between the proposed RACT allowable and the emissions used for modeling. For the turbines at least, there does appear to be a substantial difference, which causes us concern. See our General Comment # 1.

Response to H-128: The 2008 “true-up” NOx emissions for this plant were 184.66 tons per year. Following the addition of the expanded catalyst beds for the three combustion turbines, the 2017 and 2019 projected actual emissions of NOx were 174.01 tons per year. The commenter is correct that annual allowable emissions for the combustion turbines are higher than projected actual emissions. See previous responses on the use of projected actual emissions.

H-129 [EPA]: Draft SIP subsection IX.H.12.q. proposes RACT allowables for the turbines on a 30-day rolling average. Please explain how 30-day rolling averages can represent RACT in a plan that is intended to attain a 24-hour NAAQS.

Response to H-129: See previous response on 30-day rolling averages for combustion turbine NO_x emissions.

H-130 [EPA]: Draft SIP subsection IX.H.12.q uses the word "permittee" several times. We suggest using "owner/operator" or "PacifiCorp" instead.

Response to H-130: UDAQ will make the suggested changes. The term "owner/operator" will be used.

H-131 [WRA]: The emission limitations for the turbine units should be averaged over no more than 24 hours to ensure compliance with the $PM_{2.5}$ NAAQS. The following AO limits should be included in the SIP in their entirety:

- Boiler 1: 179 lb/hr, 336 ppmdv
- Boiler 2: 204 lb/hr, 336 ppmdv
- Boiler 3: 142 lb/hr, 168 ppmdv
- Combustion turbines (all three combined): 22.2 lb/hr
- Each combustion turbine: 5 ppmdv (30-day rolling average);
- 116 ppmdv (not to exceed at any time)

Response to H-131: See response to H-128 on 30-day rolling averages for combustion turbine NO_x emissions, and individual emission limits.

PACIFICORP ENERGY – LAKE SIDE POWER PLANT

H-132 [EPA]: Page 5 of the RACT Evaluation Report identifies RACT for VOC as retention of the existing oxidation catalyst systems at Block #1 and Block #2, and indicates that Block #2 has a permitted VOC emission limit of 2.8 ppmdv from each turbine/HRSG stack, on a 3-hour average. However, draft SIP subsection IX.H.13.c. does not include any proposed VOC emission limit or required controls for VOC at Block #1 or Block #2. Please explain why this is not included.

Response to H-132: The emission limits for the Lake Side turbines/HRSG units were based on the most recent AO for that plant (DAQE-AN0130310010-11), which was issued for the construction of the Block #2 turbine/HRSG units. While a VOC emission limit was established for Block #2, the inclusion of the oxidation catalyst system was for BACT control purposes as VOC emissions had not yet been established as a precursor to $PM_{2.5}$. Hence, the primary focus was for overall control of both CO and VOC. Similarly, when the oxidation catalyst control system was required for Block #1, it was for BACT purposes as the $PM_{2.5}$ nonattainment area had not been defined. Block #1 never received a VOC emission limit as demonstration of proper operation and maintenance of the control system could be achieved through compliance with the CO limit exclusively, and compliance with the CO limit and or CEM monitoring of CO was already required by Title IV, NSPS and MACT regulations.

The primary pollutant of concern from the Lake Side emission units is NO_x, which at 213.5 tons/year are approximately double the VOC emissions of 107 tons/year (2008 true-up emissions – *see* Lake Side RACT Evaluation Report, page 3). When SIP Section IX.H.13.c was drafted, the controls from the AO were determined to be RACT (page 6). Therefore, the limits from the AO were brought over with respect to NO_x. The VOC limit from Block #2 was not included because:

1) there was no equivalent limit for Block #1,
2) the control equipment was originally installed for control of both CO and VOC,
3) demonstration of proper operation and maintenance can be achieved through compliance with the CO limit required in the AO, and as required under NSPS, Title IV and MACT

H-133 [EPA]: Please explain how the emissions used for modeling for NAAQS attainment compare to the proposed allowable emissions. The table provided to us on October 31, 2013 indicates that for Lakeside Block 1, modeling was based on projected actual emissions. For Block 2, modeling was based on 90% of PTE. The only RACT allowable proposed in draft SIP subsection IX.H.13.c is 2.0 ppmdv for each turbine/HRSG stack. Please explain what the equivalent plantwide emissions are in tons per day, and what emissions in tons per day were used for modeling.

Response to H-133: From DAQE-AN0130310010-11 (the most recent AO issued to the source) the Block #2 turbine/HRSG units are limited to 18.1 lb/hr. This equates to an annual emission rate of 79.3 tons/year per turbine/HRSG as PTE assuming 8760 hours year of operation. Using 90% of PTE gives a value of 71.35 tons/year of NO_x per turbine/HRSG. However, the source anticipates operation of approximately 7,850 hours per year; approximately 90% of total capacity, which is well above average for a typical power plant. UDAQ accepted this projection as no baseload unit in the state has achieved above a 90% capacity factor. This yields a total PTE value of 63.9 tons/year of NO_x per unit.

The Block #1 units, which were operated in 2008 approximately 6500 hours/year each, had projected actual emissions of 43 tons of NO_x/year. As these units are limited by the same AO to a NO_x emission limit of 14.9 lb/hr (these units have significantly lower duct firing emissions), the values correlate.

Total modeled emissions would then be Block #1 Unit #1 projected actuals + Block #1 Unit #2 projected actuals + Block #2 Unit #1 calculated PTE + Block #2 Unit #2 calculated PTE = 43 + 43 + 63.9 + 63.9 = 213.8 tons/year.

H-134 [EPA]: Draft SIP subsection IX.H.13.c uses the word "permittee." We suggest using "owner/operator" or "PacifiCorp" instead.

Response to H-134: UDAQ will make the suggested changes. The term “owner/operator” will be used.

PAYSON CITY CORPORATION – PAYSON CITY POWER

H-135 [EPA]: Page 2 of the RACT Evaluation Report indicates that 2008 actual NO_x emissions, for all four IC engines combined, were 4.0 tons/year. From information elsewhere in the RACT Evaluation Report, it appears that this figure represents virtually all of the NO_x emissions from Payson City Power in 2008. This figure is equivalent to average daily emissions of 0.011 tons. We expect that the projected actual emissions would be only slightly higher. The table provided to us on October 31, 2013 indicates that the emissions used for NAAQS attainment modeling were the projected actual emissions. Draft SIP subsection IX.H.13.e. indicates that the proposed RACT allowable for NO_x is 1.54 tpd and 268 tons per rolling 12-month period, for all engines combined. Please explain how the projected actual emissions could be a valid basis for modeling, when the proposed allowable emissions are 140 times higher (1.54 tpd allowed versus 0.011 tpd actual). Please also explain how 1.54 tpd was calculated to be an appropriate RACT limit. No such explanation appears in the RACT Evaluation Report.

Response to H-135: The commenter is correct that annual allowable emissions for this source are higher than projected actual emissions. See previous responses on the use of projected actual emissions. The RACT Evaluation Report for Payson City Power returned a conclusion that no additional controls represented RACT for NOx emissions (see Section 3.0, page 7). UDAQ brought forward the existing daily and annual limits consistent with its practice on other such sources (see e.g. the refineries in Section IX.H.12). See previous response on the use of projected actual emissions.

H-136 [EPA]: The current NSR permit for Payson City Power, dated September of 1996, contains performance-based NO_x emission limits, in grams per kilowatt-hour, for each of the four engines. Limits are 4.96 grams per kW-hr at two engines, 7.60 grams per kW-hr at the third engine, and 8.76 grams per kW-hr at the fourth engine. Please explain why these limits were not included in draft SIP subsection IX.H.l3 .e. as part of proposed RACT.

Response to H-136: The performance based NO_x limits cited by the commenter were not established as RACT for the $PM_{2.5}$ SIP and were not included as part of the RACT Evaluation Report. They were included as part of development of the PM_{10} SIP Update for Utah County which was completed in 2002. As they were not evaluated for RACT for $PM_{2.5}$ control, they should not be included in SIP Section IX.H.13.

H-137 [EPA]: Pages 5 and 7 of the RACT Evaluation Report appear to be taking credit for VOC reductions that may result from the requirements of 40 CFR 63 subpart ZZZZ, which will require the engines at Payson City Power to meet a CO emission limitation as a surrogate for HAP emissions. The Report lists the reductions as occurring on the basis that "it is likely" that Payson City Power will be required to install oxidation catalyst controls. The RACT Summary Table projects a 1.4 tpy VOC reduction resulting from installation of oxidation catalyst by 2017. However, draft SIP subsection IX.H.13.e. does not include any proposed VOC allowable or requirement for VOC controls. If Payson City Power is being credited with a VOC emission reduction, either due to installation of new controls, or due to new requirements applicable to existing controls, then this needs to be reflected in proposed RACT requirements in the SIP.

Response to H-137: The commenter is correct that the total amount of VOC reduction being claimed as credit by UDAQ is 1.4 tons per year. The installation of oxidation catalyst for the requirements of

NESHAP 40 CFR 63 Subpart ZZZZ is aimed at controlling HAP emissions, using CO as a surrogate for those emissions. Emissions of VOC are controlled synergistically. Once the catalyst is installed and the engine is tuned for operation with that catalyst, emission reductions are automatic and do not require additional special operation. Demonstration that the catalyst is operating properly and that the engines are properly maintained can be achieved by compliance with the CO emission requirements of the NESHAP. Requiring an additional VOC emission limitation is therefore redundant.

H-138 [EPA]: The RACT Summary Table indicates that oxidation catalyst for VOC control will be installed at the IC engines by 2017. Please explain why an earlier date would not be achievable.

Response to H-138: UDAQ chose three demonstration years for modeling purposes with respect to attaining the NAAQS and the requirement of demonstrating Reasonable Further Progress; 2014, 2017 and 2019. Owing to severe delays in obtaining oxidation catalyst systems for engines of the type installed at Payson City Power, the source was unable to guarantee meeting a 2014 installation date. Meeting a 2017 demonstration date was technically feasible.

H-139 [EPA]: The draft SIP does not specify a requirement for stack testing or use of CEMS. It must do so. If stack testing will be used, the text should specify the method to be used (or cross-reference SIP subsection IX.H.11.d), the initial test date, and the frequency of testing. Also, how will power production on a daily basis be determined? And what records must the owner/operator keep?

Response to H-139: The commenter is correct that no reference to a compliance methodology is listed. This will be rectified. Paragraph iii) will be updated to include a reference to stack testing every three years, while a new paragraph iv) will be added to require daily recordkeeping of power generation from each engine.

H-140 [EPA]: The draft SIP should specifically identify the number and types of emitting units at Payson City Power, e.g. "Payson City Power has four dual-fuel internal combustion engines of size that are used to and have a generating capacity of ..."

Response to H-140: UDAQ disagrees with this comment. Individual control methodologies are not being included as specific requirements in the language of the SIP as this unnecessarily limits both the source and the agency from including better, higher efficiency controls, should such become available. See previous responses relating to individual emission controls, and the use of the RACT Summary Table. The use of daily and annual emission caps has been established as a viable emission control strategy at larger more complex sources such as petroleum refineries. UDAQ fails to see how the inclusion of additional non-emission-related restrictions on a less complex source would yield any additional emission control benefit towards attainment of the NAAQS.

PROVO CITY POWER – POWER PLANT

H-141 [EPA]: Page 2 of the RACT Evaluation Report indicates that 2008 actual NO_x emissions, for all four IC engines combined, were 20.1 tons/year. From information elsewhere in the RACT Evaluation Report, it appears that this figure represents virtually all of the NO_x emissions from Provo City Power in 2008. This figure is equivalent to average daily emissions of 0.055 tons. We expect that the projected actual emissions would be only slightly higher. The table provided to us on October 31, 2013 indicates that the emissions used for NAAQS attainment modeling were the projected actual emissions. Draft SIP subsection IX.H.l3.f. indicates that the proposed RACT allowable for NO_x is 2.45 tpd and 254 tons per rolling 12-month period for the overall plant. Please explain how the projected actual emissions could be a valid basis for modeling, when the proposed allowable emissions are at least 44 times higher (2.45 tpd allowed versus 0.055 tpd actual). Please also explain how 2.45 tpd was calculated to be an appropriate RACT limit. No such explanation appears in the RACT Evaluation Report.

Response to H-141: The commenter is correct that annual allowable emissions for this source are higher than projected actual emissions. See response to H-135 on the use of projected actual emissions.

H-142 [EPA]: The current NSR permit for Provo City Power, dated December of 2004, contains performance-based NO_x emission limits, in grams per kilowatt-hour and ppmdv, for each of the boilers and engines. The limits are 1.46 grams per kW-hr and 155 ppmdv at each of two boilers, and 10.4 grams per kW-hr and 1,660 ppmdv at each of four engines. Please explain why these emission limits, covering the main emitting units at the facility, were not included as part of RACT.

Response to H-142: The performance based NO_x limits cited by the commenter were not established as RACT for the $PM_{2.5}$ SIP and were not included as part of the RACT Evaluation Report. They were included as part of development of the PM_{10} SIP Update for Utah County which was completed in 2002. As they were not evaluated for RACT for $PM_{2.5}$ control, they should not be included in SIP Section IX.H.13.

H-143 [EPA]: Pages 5 and 10 of the RACT Evaluation Report appear to be taking credit for VOC reductions at the four IC engines that may result from the requirements of 40 CFR 63 subpart ZZZZ, which will require the engines at Provo City Power to meet a CO emission limitation as a surrogate for HAP emissions. The Report lists the reductions as occurring in 2017 as a result of the addition of oxidation catalyst controls. The RACT Summary Table projects a 1.4 tpy VOC reduction resulting from installation of oxidation catalyst by 2017. However, draft SIP subsection IX.H.13 .f. does not include any proposed VOC allowable or requirement for VOC controls. If Provo City Power is being credited with a VOC emission reduction, either due to installation of new controls, or due to new requirements applicable to existing controls, then this needs to be reflected in proposed RACT requirements in the SIP.

Response to H-143: The commenter is correct that the total amount of VOC reduction being claimed as credit by UDAQ is 1.4 tons per year. The installation of oxidation catalyst for the requirements of NESHAP 40 CFR 63 Subpart ZZZZ is aimed at controlling HAP emissions, using CO as a surrogate for those emissions. Emissions of VOC are controlled synergistically. Once the catalyst is installed and the engine is tuned for operation with that catalyst, emission reductions are automatic and do not require additional special operation. Demonstration that the catalyst is operating properly and that the engines are properly maintained can be achieved by compliance with the CO emission requirements of the NESHAP. Requiring an additional VOC emission limitation is therefore redundant.

H-144 [EPA]: The RACT Summary Table indicates that oxidation catalyst for VOC control will be installed at the IC engines by 2017. Please explain why an earlier date would not be achievable.

Response to H-144: UDAQ chose three demonstration years for modeling purposes with respect to attaining the NAAQS and the requirement of demonstrating Reasonable Further Progress; 2014, 2017 and 2019. Provo City Power is in the process of installing and testing this equipment at the present time. However, as this source falls into a source category with Payson City Power and Springville City Power, two sources which are unable to guarantee a 2017 demonstration date, UDAQ chose to establish a date all three sources could meet equally and equitably.

H-145 [EPA]: Regarding compliance demonstration requirements:

i) Stack testing is proposed to be required every 8,760 hours of operation and/or at least every five years. We are concerned with stack test frequencies longer than one year. Please explain why this test frequency is sufficient to ensure continuous compliance with the limits.

ii) The text should specify the date for the initial stack test for each unit and the test method to be used (or cross-reference subsection IX.H.11.d.).

iii) Subsection IX.H.13.f.iii. should be clarified to say that stack testing is required every 8,760 hours of operation or every five years, whichever occurs sooner.

iv) It is not clear how power production will be determined or how 12-month rolling totals of power production would be adequate to determine compliance with a daily limit.

v) The SIP needs to specify what records the owner/operator must keep.

vi) The draft SIP should specifically identify the number and types of emitting units at Provo City Power, e.g. "Provo City Power has four dual-fuel internal combustion engines of __ size that are used to and have a generating capacity of ____ , as well as two natural gas fired boilers of size that are used to ____ and have a generating capacity of "

Response to H-145:

i) With regards to long interval stack test frequencies. The units in existence at this source are in operation extremely infrequently. The purpose of the language was to require a minimum stack test frequency – but to also base that upon operation of the engines and not subject the source to additional testing for an engine which may not have been in operation since the previous test was performed (if the frequency were to be too great).

ii) The initial stack test for this source has long since been performed. This is not a new source, and none of the emission units are new either. The cross-reference with SIP Section IX.H.11.d is not required, as this is already accomplished with the language found in SIP Section IX.H.11

iii) Commenter's suggestion is noted and is reasonable. The suggested change is acceptable to UDAQ.

iv) The commenter is correct that no reference to an overall compliance methodology is included. This will be rectified. A requirement to record the daily power generated by each engine and boiler will be added to paragraph iv). This will replace the current requirement to determine power production on a rolling 12-month basis.

v) See previous.

vi) UDAQ disagrees with this comment. Individual control methodologies are not being included as specific requirements in the language of the SIP as this unnecessarily limits both the source and the agency from including better, higher efficiency controls, should such become available. See previous responses relating to individual emission controls, and the use of the RACT Summary Table. The use of daily and annual emission caps has been established as a viable emission control strategy at larger more complex sources such as petroleum refineries. UDAQ fails to see how the inclusion of additional non-emission-related restrictions on a less complex source would yield any additional emission control benefit towards attainment of the NAAQS.

SPRINGVILLE CITY CORPORATION – WHITEHEAD POWER PLANT

H-146 [EPA]: Page 2 of the RACT Evaluation Report indicates that 2008 actual NO_x emissions, for all seven IC engines combined, were 0.1 tons/year. From information elsewhere in the RACT Evaluation Report, it appears that this figure represents virtually all of the NO_x emissions from the plant in 2008. This figure is equivalent to average daily emissions of 0.00027 tons. We expect that the projected actual emissions would be only slightly higher. The table provided to us on October 31, 2013 indicates that the emissions used for NAAQS attainment modeling were the projected actual emissions. Draft SIP subsection IX.H.13.g. indicates that the proposed RACT allowable for NO_x is 1.68 tpd and 248 tons per rolling 12-month period, for all engines combined. Please explain how the projected actual emissions could be a valid basis for modeling, when the proposed allowable emissions are approximately six thousand times higher (1.68 tpd allowed versus 0.00027 tpd actual). Please also explain how 1.68 tpd was calculated to be an appropriate RACT limit. No such explanation appears in the RACT Evaluation Report.

Response to H-146: The commenter is correct that annual allowable emissions for this source are higher than projected actual emissions. See previous responses on the use of projected actual emissions.

H-147 [EPA]: The current NSR permit, dated December of2003, contains performance-based NO_x emission limits, in lb/hr and grams per kilowatt-hour for each of seven engines. Limits are 27.00 lb/hr and 2.50 grams per kW-hr at the four Enterprise engines, and 24.00 lb/hr and 4.90 grams per kW-hr at each of the three General Motors EMD engines. Please explain why these emission limits, covering the main emitting units at the facility, were not included as part of RACT.

Response to H-147: The performance based NO_x limits cited by the commenter were not established as RACT for the $PM_{2.5}$ SIP and were not included as part of the RACT Evaluation Report. They were included as part of development of the PM_{10} SIP Update for Utah County which was completed in 2002. As they were not evaluated for RACT for $PM_{2.5}$ control, they should not be included in SIP Section IX.H.13.

H-148 [EPA]: Pages 4 and 10 of the RACT Evaluation Report appear to be taking credit for VOC reductions that may result from the requirements of 40 CFR 63 subpart ZZZZ, which will require the engines at the Whitehead power plant to meet a CO emission limitation as a surrogate for HAP emissions. The Report lists the reductions as occurring on the basis that " it is likely" that the plant will be required to install oxidation catalyst controls. However, draft SIP subsection IX.H.13.g. does not include any proposed VOC allowable or any proposed requirement for VOC controls. If the plant is being credited with a VOC emission reduction, either due to new controls, or due to new requirements applicable to existing controls, then this needs to be reflected in proposed RACT requirements for VOCs in the SIP.

Response to H-148: The installation of oxidation catalyst for the requirements of NESHAP 40 CFR 63 Subpart ZZZZ is aimed at controlling HAP emissions, using CO as a surrogate for those emissions. Emissions of VOC are controlled synergistically. Once the catalyst is installed and the engine is tuned for operation with that catalyst, emission reductions are automatic and do not require additional special operation. Demonstration that the catalyst is operating properly and that the engines are properly maintained can be achieved by compliance with the CO emission requirements of the NESHAP. Requiring an additional VOC emission limitation is therefore redundant.

H-149 [EPA]: The RACT Summary Table indicates that oxidation catalyst for VOC control will be installed at the IC engines by 2017. Please explain why an earlier date would not be achievable.

Response to H-149: UDAQ chose three demonstration years for modeling purposes with respect to attaining the NAAQS and the requirement of demonstrating Reasonable Further Progress; 2014, 2017 and 2019. Owing to severe delays in obtaining oxidation catalyst systems for engines of the type installed at Springville City Power, the source was unable to guarantee meeting a 2014 installation date. Meeting a 2017 demonstration date was technically feasible.

H-150 [EPA]: The draft SIP should specify the requirement for the owner/operator to operate and maintain CEMS and output meters for each engine, and state or cross-reference the relevant CEMS requirements.

Response to H-150: The requirements for CEM operation are found in SIP section IX.H.11.f.

H-151 [EPA]: The draft SIP should specifically identify the number and types of emitting units at Springville City Power, e.g. "Springville City Power has seven dual-fuel internal combustion engines of __ size that are used to and have a generating capacity of _ __ _ as well as one natural gas fired boiler of size that is used to and has a generating capacity of, as well as one boiler fired on digester gas of size that is used to and has a generating capacity of ..."

Response to H-151: UDAQ disagrees with this comment. Individual control methodologies are not being included as specific requirements in the language of the SIP as this unnecessarily limits both the source and the agency from including better, higher efficiency controls, should such become available. See previous responses relating to individual emission controls, and the use of the RACT Summary Table. The use of daily and annual emission caps has been established as a viable emission control strategy at larger more complex sources such as petroleum refineries. UDAQ fails to see how the inclusion of additional non-emission-related restrictions on a less complex source would yield any additional emission control benefit towards attainment of the NAAQS.

WASATCH INTEGRATED WASTE MANAGEMENT

H-152 [EPA]: Draft SIP subsection IX.H.l2.v. requires SNCR to be installed and operating for NOx control by January 1, 2019. Please explain why an earlier date would not be achievable.

Response to H-152: The DAQ required point sources to identify implementation timeframes. The DAQ recognizes that most of the pollution control technologies being required of industry are not “off the shelf”, and a significant lead time is required to design, purchase, install, test and implement these technologies. DAQ agrees however, that more documentation is necessary to establish that these implementation dates are “as expeditious as practicable”. As we now consider the additional planning requirements of subpart 4, there are a number of areas in which these draft SIPs will have to be supplemented or revised.

The SNCR installation date provides for compliance with the NAAQS attainment modeling by 2019.

H-153 [EPA]: Draft SIP subsection IX.H.l2.v. specifies a NOx emission limit of 350 ppmdv, but does not say whether the limit is already in effect, or is intended to go into effect after installation of SNCR. The current NSR permit (Approval Order) dated October 22, 2007, already specifies 350 ppmdv, therefore it appears to us that subsection IX.H.12.v. needs to specify what new NOx limit will go into effect after installation of SNCR, along with a deadline for initial compliance testing and a test method.

Response to H-153: The NO_x emission limitation of 350 ppmdv is required by the current NSR Approval Order DAQE-AN101290020-12. UDAQ will require a modification to the Approval Order to install the SNCR technology on each of the two (2) waste incinerators. The new Approval Order will establish a new NO_x emission limitation for each waste incinerator as well as a NO_x stack testing requirement, testing method, and testing frequency. Testing for the new SNCR technology would be required within 180 days of equipment installation.

H-154 [EPA]: Draft SIP subsection IX.H.l2. v. says compliance shall be determined by CEMS. If a NOx CEMS is not already installed and certified, then a deadline should be specified by which it must be certified. Also, the draft SIP subsection doesn't clearly require the operation of CEMS. This does not appear to be addressed by the General Requirements at draft SIP subsection IX.H.11. Requirements to operate and maintain CEMS should be included in IX.H.11 or in IX.H.l2.v.

Response to H-154: The requirement for NO_x CEMS is established in the NSR Approval Order DAQE-AN101290020-12.

H-155 [EPA]: Page 1 of the RACT Evaluation Report indicates that 40 CFR 60, subpart BBBB (emission guidelines for small municipal waste combustors) applies to this source, but does not identify it as RACT. Subpart BBBB contains numerous requirements for emission control. Please explain why the requirements that affect control of $PM_{2.5}$, $S0_2$, NOx and VOC should not be considered part of RACT and incorporated as requirements in draft SIP subsection IX.H.l2.v., along with a requirement to continue operating and maintaining the existing emission control equipment for these pollutants. As we explained in the General Comments above, for an approvable attainment demonstration, the state needs to identify the existing local measures in the area that contribute to attainment of the NAAQS in that area, so that EPA can approve those measures specifically as RACT.

Response to H-155: The NSR Approval Order DAQE-AN101290020-12 requires that the Waste Heat recovery boilers are governed by 40 CFR 60, Subpart BBBB. This would include all applicable limitations found within 40 CFR 60, Subpart BBBB. Therefore, because it has already been addressed and included in the Approval Order, the requirements of Subpart BBB were not listed as SIP limitations to avoid redundancy.

H-156 [EPA]: Page 5 of the RACT Evaluation Report indicates that RACT for PM2.5, VOC and NOx includes replacement of the emergency diesel generator with a Tier 4 generator upon equipment replacement, but says there is no timeline established for this replacement at this time. Draft SIP subsection IX.H.12.v. says nothing about replacing this generator. Please explain why the state considers this to be RACT when there is no timeline and no mention of it as a requirement in the draft SIP subsection.

Response to H-156: Wasatch Integrated Waste Management has agreed to replace the emergency diesel generator with a Tier 4 series generator upon replacement of this equipment. Because they are not able to commit to an implementation date for this equipment it was not included as a SIP RACT requirement requiring a necessary SIP limit. The modeled NAAQS attainment demonstration did not include the emissions reductions for a Tier 4 engine. Therefore, the UDAQ does not feel it is necessary to address the Diesel generator replacement in the SIP. This lack of an implementation date can be addressed during development of the serious nonattainment SIP.

H-157 [EPA]: Page 5 of the RACT Evaluation Report also indicates that RACT includes the requirements for municipal solid waste landfills at 40 CFR 63, subpart AAAA. However, no specific requirements are cited and draft SIP subsection IX.H.12.v. does not include any requirement to comply with 40 CFR 63 subpart AAAA. Please explain whether the state considers the landfill to be part of this source for purposes of the $PM_{2.5}$ SIP, and if so, whether the state considers the landfill rule to be part of RACT. We note that the current NSR permit includes the landfill.

Response to H-157: The NSR Approval Order DAQE-AN101290020-12 specifically states that the Landfill is part of the source and subjects Wasatch Integrated Waste Management to 40 CFR 63, Subpart AAAA requirements. This would include all applicable limitations found within 40 CFR 63, Subpart AAAA. Therefore, because it has already been addressed and included in the Approval Order, the requirements of Subpart AAAA were not listed as SIP limitations to avoid redundancy.

CENTRAL VALLEY WATER RECLAMATION FACILITY: WASTEWATER TREATMENT PLANT

H-158 [EPA]: For NO_x control, page 4 of the RACT Evaluation Report recommends that RACT be no add-on controls. However, page 3 of the Report indicates that Good Combustion Practices (GCP) is a technically feasible RACT option and offers no reason why GCP should be ruled out as RACT. Please explain whether the proposed performance-based RACT limits for NOx in draft SIP subsection IX.H.12.e. (which are 1.75 grams per horsepower-hour at the 1150 kW engine generators and 1.8 grams per horsepower-hour at the 1340 kW engine generators) are intended to represent GCP. If GCP is intended to be reflected in terms of some other type of requirement, then please explain why this was not included in IX.H.12.e.

Response to H-158: GCP as RACT was implied and therefore was simply omitted from the final determination, GCP and the NOx limits are recommended as RACT. Section 2.1 "Selection of RACT" has been modified to say as follows:

> *DAQ recommends GCP, the existing NOx limitations and no add on controls be installed on the five IC engines as RACT for the control of NOx emissions.*

H-159 [EPA]: For VOC control, page 4 of the RACT Evaluation Report indicates that installation of oxidation catalyst for VOC control at the five IC engines is not economically feasible, but offers no cost information to support this conclusion. This is not sufficient to satisfy RACT requirements. Please explain what information was used to arrive at this conclusion.

Response to H-159: These engines are essentially emergency engines. Oxidation catalysts could only reduce emissions for all five engines combined by approximately 3.5 tpy, less than a ton per engine. This is not economically reasonable to impose as RACT for the control of VOCs on emergency engines.

H-160 [EPA]: The table provided to us on October 31, 2013 indicates that the emissions used for NAAQS attainment modeling were "2008 Actual." Pages 2 and 5 of the RACT Evaluation Report indicate that the 2008 total NOx emissions (for the IC engines and the digesters combined) were 28.41 tons. This figure is equivalent to average daily emissions of 0.078 tons. Draft SIP subsection IX.H.l2.e., however, proposes to allow NOx emissions from the IC engines of 0.648 tpd and 205.6 tpy. No emission limits or operational limits are proposed for the digesters. Please explain how the 2008 actual emissions could be a valid basis for modeling, when the proposed allowable emissions are at least eight times higher (0.648 tpd allowed versus 0.078 tpd actual). Please also explain how 0.648 tpd was calculated to be an appropriate RACT limit. No such explanation appears in the RACT Evaluation Report.

Response H-160: The commenter is correct that annual allowable emissions for this source are higher than projected actual emissions. See previous responses on the use of projected actual emissions.

Section 2.1 of the CVWRF RACT analysis discusses that the 0.648 tpd was calculated and set in the PM_{10} SIP and carried forward into this SIP. The RACT analysis did not establish any additional limits so these previously approved SIP limits were brought forward.

Section 2.3 of the CVWRF RACT analysis discusses how in 2011 the facility voluntarily implemented a two-stage mode for controlling VOC emissions from the digesters, which reduced their VOC emissions by approximately 85%. This two-stage system was determined to be RACT for control of VOCs from the digesters. Requiring inlet and outlet VOC stack testing to verify the 85% efficiency is not reasonable to put on a public utility that cannot be limited in throughput. It was reasonable to establish that CVWRF continue to utilize best operational practices by maintaining the two-stage system and not limit the facility in the amount of water they can treat.

H-161 [EPA]: The proposed SIP language should be clarified as follows to ensure the enforceability of emission limits:

i) Subparagraph i should clearly state that Central Valley Water Reclamation shall maintain and operate electrical meters to record the electricity production at each of the engines. The text should also identify the current engines at the plant.

ii) In Subparagraphs ii and iii, please state the number of the 1150 kw and 1340 kw engine generators.

iii) Subparagraph iv should clarify that compliance with the emission limits in Subparagraphs ii and iii shall be determined by stack test, and that compliance with the emission limit in Subparagraph i shall be determined through use of emission factors. Also, Subparagraph iv should state the required frequency of stack tests. If the required frequency will be less than once per year, please explain why such a frequency is adequate to ensure continuous compliance with the limits.

Response to H-161:

i) UDAQ disagrees that this level of precision is required. It is implied that the electrical power output of each engine is monitored based on the language of the compliance paragraph. This necessarily requires that each engine is monitored by individual electrical meter.

ii) UDAQ disagrees with this comment. Individual control methodologies are not being included as specific requirements in the language of the SIP as this unnecessarily limits both the source and the agency from including better, higher efficiency controls, should such become available. See previous responses relating to individual emission controls, and the use of the RACT Summary Table. The use of daily and annual emission caps has been established as a viable emission control strategy at larger more complex sources such as petroleum refineries. UDAQ fails to see how the inclusion of additional non-emission-related restrictions on a less complex source would yield any additional emission control benefit towards attainment of the NAAQS.

iii) The stack test requirements of subparagraphs ii and iii are derived from the latest AO (DAQE-AN0104140011-09), which included only a test every 5-years requirement. This minimum stack testing frequency is already established by rule, and is included by default in the stack testing requirements of the SIP in Section IX.H.11.e. More frequent stack testing is not required, as demonstration of attainment of the NAAQS is accomplished through the daily source-wide SIP emission Cap and not through the individual performance-based RACT limit.

GREAT SALT LAKE MINERALS CORPORATION (GSLM): PRODUCTION PLANT

H-162 [EPA]: The RACT Summary Table indicates that a PM emission limit of0.010 gr/dscf will be imposed at all baghouses and scrubbers on salt/SOP production lines by 2017. Draft SIP subsection IX.H.12.h. requires stack tests by January 1, 2017. Page 13 of the RACT Evaluation Report indicates, however, that with the sole exception of wet scrubber AH-013 , all existing baghouses and scrubbers at GSLM can already meet 0.010 gr/dscf, as demonstrated by recent stack test results. The proposed limit "will be more representative of actual operations operating at RACT levels." Further, the existing emission limit for nine of the eleven PM control devices is already at or near 0.01 gr/dscf in the current NSR permit. Please explain why an earlier date than 2017 would not be achievable. It appears that only AH-013 needs time to comply.

Response to H-162: The RACT analysis submitted by GSLM stated that their PM_{10} controls could meet BACT level of control but did not elaborate or provide any verification of this statement. Therefore, DAQ provided a blanket requirement that all PM_{10} control equipment must do stack testing to verify compliance with the established 0.01 gr/dscf BACT limit while allowing time for GSLM to replace or retrofit any equipment that could not meet this level.

H-163 [EPA]: Draft SIP subsection IX.H.12.h. does not require stack testing for condensable PM. Please explain why condensable PM is not addressed. This is not explained in the RACT Evaluation Report.

Response to H-163: Section 2.3 of GSLM's RACT Analysis specifies that the majority of PM emissions at GSLM are PM_{10} and that by controlling PM_{10} emissions, $PM_{2.5}$ emission will be reduced in kind. The following language has been included in the testing requirements for the baghouses and scrubbers.

> *Within one hundred and twenty (120) days after the initial compliance test date required above for each baghouse/scrubber, GSLM shall submit a Notice of Intent to DAQ in which a $PM_{2.5}$ emission limit in grains/dscf and pounds/hour is proposed.*

H-164 [EPA]: The RACT Summary Table indicates that ultra low NOx burners (ULNB) will be required at Boilers # 1 and #2 by 2017. Draft SIP subsection IX.H.12.h. requires stack tests by January 1, 2017, to demonstrate compliance with a proposed NOx emission limit of 9.0 ppmdv. Please explain why an earlier date would not be achievable.

Response to H-164: The GSLM RACT analysis actual states that the boilers continue to utilize existing ULNB technology. The limit document has been reformatted to make clear the testing requirements of the boilers. Per the AO, the boilers are stack tested for NOx every three years starting in 2013 which will be reflected in the SIP limit.

H-164 [EPA]: Please explain how the emissions used for NAAQS attainment modeling compare to the emissions that are proposed to be allowed, on a plant wide daily basis. The table provided to us on October 31, 2013 indicates that the emissions used for modeling were "2008 Actual." The RACT Evaluation Report does not indicate what the emissions were in 2008. There is also no information on what the allowable emissions will be, on a plant wide daily basis, after RACT is applied. Our objective here is to see if there is a substantial difference between the proposed allowable emissions and the emissions used for modeling.

Response to H-164: The commenter is incorrect, 2008 actual emissions were included throughout the RACT analysis. However, a comparison of PTE to 2008 actual emissions is provided below for PM_{10} emitting equipment.

See response H-135 on the use of projected actual emissions.

Equipment		PM_{10} Potential to Emit (tpy)	PM_{10} 2008 Actuals (tpy)
Salt Plant Dryer D-001	BH-014 Baghouse	5.65	0.29
SOP Plant Dryer D-002	BH-008 Baghouse	16.29	0.71
SOP Plant Dryer D-003	AH-013 Wet Scrubber (Pre 1969)	6.35	2.27
SOP Plant D-004	AH-075 Wet Scrubber	11.65	0.71
SOP Plant Heater D-005	BH-006	7.72	6.51
Salt Plant Dryer D-501	AH-513 Wet Cyclone & Wet Scrubber	6.35	0.24
SOP Plant Loadout	BH-001 Baghouse	7.18	0.14
SOP Silos	BH-002 Baghouse	6.00	0.42
SOP Plant Compact	BH-005 Baghouse	3.94	0.58
Salt Plant Dryer D-501	BH-501 Baghouse	3.94	0.04
Bulk Truck Loadout	BH-502 Baghouse	0.58	0.34
Salt Plant Compaction/Loading	AH-500 Wet Scrubber	33.51	0.76
Salt Plant Screening	AH-502 Wet Scrubber	22.95	0.05
Mag Chloride Plant	High efficiency venturi wet scrubber	--	0.33

H-165 [EPA]: The RACT Summary Table projects emission reductions by 2017 of 22.12 tpy of NOx (due to installation of ULNB) and 7.97 tpy of PM (due to imposition of more stringent allowables in gr/dscf at existing PM controls). It is unclear why the state would use 2008 actuals as the basis for modeling, when emission reductions through application of new controls as RACT are projected after 2008. It appears that no credit for these reductions is reflected in the modeling. Please explain.

Response to H-165: As stated in the RACT analysis Section 3.0, the 7.97 tpy of PM_{10} reduction came from the replacement of AH-013. As discussed in Section 2.1 of the RACT analysis, the reduction of

77% of NOx from the installation of LNB technology was a reduction from 2008 actual emissions. Both the replacement of AH-013 and LNB technology reductions are reflected in the RACT analysis and the model.

H-166 [EPA]: Stack testing is proposed to be required at a minimum of every five years. We are concerned with stack test frequencies longer than one year. Please explain why these test frequencies are sufficient to ensure continuous compliance with the limits.

Response to H-166: Stack testing frequency is based on engineering judgment and the permit writer's knowledge regarding the specific sources process and history. How close a source is to a threshold (significance, PSD, etc.), what existing stack requirements are in place, and whether the equipment is controlled with industry wide accepted technology are some things considered when setting testing frequency. The RACT analysis is proposing to implement the AO and Title V permit established stack testing requirements.

H-167 [EPA]: Please explain why emission limits are proposed in terms of PM_{10} rather than $PM_{2.5}$.

Response to H-167: Section 2.3 of GSLM's RACT Analysis specifies that the majority of PM emissions at GSLM are PM_{10} and that by controlling PM_{10} emissions, $PM_{2.5}$ emission will be reduced in kind. The following language has been included in the testing requirements for the baghouses and scrubbers.

> *Within one hundred and twenty (120) days after the initial compliance test date required above for each baghouse/scrubber, GSLM shall submit a Notice of Intent to DAQ in which a $PM_{2.5}$ emission limit in grains/dscf and pounds/hour is proposed.*

H-168 [GSLM]: *GSLM is requesting to incorporate by reference the comments made by the Utah Manufacturers Association, Utah Mining Association, and Utah Petroleum Association dated October 31, 2013.*

Response to H-168: Comment is noted. No response required.

H-169 [GSLM]: "Apply RACT not BACT to GSLM." GSLM is stating that the high costs imposed in the RACT are "too high and inappropriately elevates the PM requirements from RACT to the more stringent best available control technology." The commenter includes the definition of RACT from 44 Fed. Reg. 53762, September 17, 1979.

Response to h-168: With respect to comments on RACT, UDAQ thanks the commenter for the comment. While final RACT determinations were made at the December 4, 2013 meeting of the Utah Air Quality Board when it voted to accept SIP Subsection IX.A.21: Control Measures for Area and Point Sources, Fine Particulate Matter, $PM_{2.5}$ SIP for the Salt Lake, UT Nonattainment Area, UDAQ anticipates the need to submit a new BACT/RACT analysis as part of a Subpart 4 Serious $PM_{2.5}$ Nonattainment Area SIP in the near future, and would invite the commenter to resubmit this comment at that time.

H-170 [GSLM]: "Appropriate Stack Test Methods." *The commenter is referencing Subsection IX.H.12.h.iii of the proposed SIP.*

Response to H-170: See previous response to problems with PM analytical methods (H-162, 163, 164, and 166).

H-171 [GSLM]: "Emission Limits Should apply to $PM_{2.5}$ Emissions, Not PM_{10} Emissions."

Response to H-171: Per the request of the commenter, DAQ will impose a $PM_{2.5}$ limitation on all baghouses and scrubbers. The following language will be added to the SIP limitations to account for PM2.5:

> *Within one hundred and twenty (120) days after the initial compliance test date required above for each baghouse/scrubber, GSLM shall submit a Notice of Intent to DAQ in which a PM2.5 emission limit in grains/dscf and pounds/hour is proposed.*

H-172 [GSLM]: "DAQ Lacks Justification to Impose a Blanket Requirement for Ultra-Low NOx Burners."

Response to H-172: Ultra-Low NOx Burners were determined to be RACT as approved by the Utah Air Quality Board on December 4, 2013.

Initially GSLM did not submit a thorough RACT analysis for TechLaw or DAQ to review. What GSLM did provide did not eliminate Low NOx or Ultra-Low NOx technologies as technically feasible. GSLM also did not provide an annualized cost analysis for each burner to determine if the technology was economically feasible for controlling NOx. DAQ based the initial RACT analysis on available information and that Low NOx and Ultra Low NOx technology is available. The comment is otherwise noted, no changes were made to the AO.

H-173 [GSLM]: "DAQ Modeling Does Not Necessarily Justify PM Controls on GSLM." *The commenter is challenging the designated PM2.5 nonattaiment area.*

UDAQ Response: The designation of the PM2.5 nonattainment boundaries was not the subject of this public comment period. The comment is noted

H-174 [GSLM]: GSLM submitted a RACT analysis with their $PM_{2.5}$ SIP Limit comments and asked DAQ to re-evaluate RACT based on this additional information. The RACT public comment period ended on October 31, 2013, prior to GSLM submitting their RACT comments.

Response to H-174: The RACT analysis for GSLM was approved by the Utah Air Quality Board on December 4, 2013. Although the RACT comments were submitted outside of the public comment period, DAQ has prepared the following responses the commenters RACT analysis as they relate to the SIP limits.

PM Control

The commenter lists the flow rates of various baghouses in dscfm; however the RACT analysis lists the flow rates based on what is listed in the AO in acfm.

Based on the stack testing results, GSLM provided documentation to DAQ that all baghouses could meet their manufacturer's guarantee and the BACT limit of 0.01 gr/dscf. Therefore, DAQ's RACT analysis did not determine that any other baghouses need to be replaced to meet RACT, only to enforce this BACT level. DAQ will modify the PM_{10} limits to more accurately reflect the manufacturer's guarantee of 0.01 gr/dscf, as opposed to the 0.010 gr/dscf limit originally proposed as RACT.

The commenter included a cost analysis for the replacement of AH-500 and AH-502 in Table 3-2. However, this table lists the "Salt Cooler Baghouse" which does not appear in the AO. DAQ assumes that the commenter actually referencing the Salt Plant Screening equipment that is currently controlled with AH-502. These costs estimates have been included in the RACT analysis. The replacement of AH-502 with a baghouse is economically feasible at $15,606/ton PM_{10} removal and the RACT analysis has been modified to reflect this.

<u>NOx Control</u>

GSLM originally did not provide a RACT analysis for the control of NOx for the facility dryers. However, the commenter has submitted a RACT analysis. The commenter proposes that there is Low NOx Burner technology that is equivalent to the Ultra Low NOx burner technology relied upon in the RACT analysis of 77% NOx removal efficiency.

With the exception of emissions from D-003, it is unclear how the commenter calculated the NOx reductions as they appear in Table 3-3 or in the Reference Document titled Cost Analysis for LoNOx Burners. However, DAQ used 2008 actual baseline emissions for each dryer with a 77% NOx removal efficiency as proposed by the commenter. Using these reductions along with an annualized cost per dryer proposed by the commenter of $65,880, it is economically feasible to retrofit the following dryers with Low NOx burner technology.

NOx Technically Feasible Control Options Cost Analysis Dryers (Low NOx Technology)			
Dryer	**2008 Actual Emissions**	**NOx Reduction (tpy)**	**Cost ($) / Ton Reduction**
D-001	**3.86**	**2.97**	**$22,182**
D-002	**4.65**	**3.58**	**$18,402**
D-003	**2.44**	**2.07**	**$27,565**
D-004	**4.65**	**3.58**	**$18,402**
D-005	**4.50**	**3.46**	**$19,404**
D-501	**8.40**	**6.46**	**$10,198**
Average Cost ($) / Ton Reduction			**$17,870**

The limitation on the dryers shall be modified to read as follows:

> *By January 1, 2017, Low NOx burner technology with a minimum manufacturer guarantee of 77% NOx removal efficiency shall be in operation on all dryers.*

The comment is otherwise noted.

H-175 [GSLM]: The Emission Limits contain no PM2.5 emission limit for Great Salt Lake Minerals operations. There is no basis in the record to explain why RACT for this facility is not required until 2017 or why stack tests to establish compliance with the NOX emission limit can be delayed until 2017. To allow subsequent stack testing to be performed once every five years also does not represent RACT. Finally, the Director predicts that emissions of both PM2.5 and NOX will increase at the Great Salt Lake Minerals facility by 2019. Plainly, RACT should be considered and implemented that will result in emission reductions at this plant.

Response to H-175: The RACT analysis submitted by GSLM stated that their PM_{10} controls could meet BACT level of control but did not elaborate or provide any verification of this statement. Therefore, DAQ provided a blanket requirement that all PM_{10} control equipment must do stack testing to verify compliance with the established 0.01 gr/dscf BACT limit while allowing time for GSLM to replace or retrofit any equipment that could not meet this level.

The commenter is incorrect; per the AO, both boilers are tested every 3 years starting in 2013. The GSLM limits document has been reformatted to make this clearer. The commenter has not provided a regulator reference to back up the statement that performing stack tests "once every five years also does not represent RACT" nor is DAQ aware of test frequency requirements that have been established to represent RACT. Stack testing frequency is based on engineering judgment and the permit writer's knowledge regarding the specific sources process and history. How close a source is to a threshold (significance, PSD, etc.), what existing stack requirements are in place, and whether the equipment is controlled with industry wide accepted technology are some things considered when setting testing frequency. The RACT analysis is proposing to implement the AO and Title V permit established stack testing requirements.

The increase in $PM_{2.5}$ by 2019 in the modeling represents the inclusion of industry specific growth factors provided by the Governor's Office of Planning and Budget (GOPB) as discussed in the Technical Support Documentation (TSD).

CHEMICAL LIME COMPANY (LHOIST NORTH AMERICA)

H-176 [EPA]: Draft SIP subsection IX.H.l2.f. requires installation of SNCR technology for NOx control and a baghouse for PM control on the Lime Production Kiln "upon source start-up." Page 1 of the RACT Evaluation Report states that the kiln has been in "temporary care and maintenance mode" since November of 2008. It is unclear whether this means the kiln is now completely shut down. Please explain whether "source start-up" means a cold start-up after a complete shutdown.

Response to H-176: The kiln is currently shut down; meaning that no fuel source is being fired to keep the kiln heated or in a state of ready operation. Therefore; kiln start-up would require a cold start-up. "Temporary care and maintenance mode" means that the Chemical Lime (LHoist) facility is undergoing basic day-to-day activities such as security, plant clean-up operations, etc. There is no lime being manufactured and the kiln is not being operated.

H-177 [EPA]: The RACT Summary Table indicates that a baghouse will be installed at the lime processing rotary kiln for $PM_{2.5}$ control by 2019, and SNCR will be installed at the kiln for NOx control by 2019. Please explain why an earlier date would not be achievable.

Response to H-177: Chemical Lime Company (LHoist North America) Grantsville plant shut-down in 2008 due to company and market economic reasons. Because of this shut-down, LHoist is unsure of a future start-up date where the lime kiln would be able to be in full operational status. Therefore, requiring baghouse and SNCR controls prior to 2019 would not be reasonable as such a start-up date is still unknown.

H-178 [EPA]: Draft SIP subsection IX.H.l2.f. does not include any proposed NOx emission limit after installation of SNCR technology at the kiln, nor does it indicate whether the SNCR will even be tested after it is installed. If Chemical Lime is being credited with a NOx emission reduction due to eventual installation of SNCR, then this needs to be reflected in terms of a NOx emission limit and appropriate compliance testing requirements by a specific deadline.

Response to H-178: UDAQ will require a NO_x emission limitation as well as a NO_x stack testing requirement prior to plant start-up. This will be required through the UDAQ permitting process and an Approval Order/Title V permit modification for this activity. Therefore, the requirements addressed would be covered through the permitting process prior to plant start-up and are not necessary for the $PM_{2.5}$ SIP process.

H-179 [EPA]: Please explain how the emissions used for NAAQS attainment modeling compare to the emissions that are proposed to be allowed at Chemical Lime, on a plant wide daily basis. The table provided to us on October 31, 2013 lists emission figures in tons/year that were used for modeling for Chemical Lime. The basis for those figures is not indicated. We do not know if those figures might represent the proposed RACT allowable, i.e., installation of SNCR and a baghouse at the kiln after it resumes operation. Our objective here is to see if there is a substantial difference between the proposed allowable emissions and the emissions used for modeling.

Response to H-179: The emissions used for NAAQS attainment modeling were based upon the RACT analysis submitted. This analysis included the installation of a baghouse and SNCR control. While the installation of the baghouse and SNCR control is not required until 2019 and/or upon a future start-up date; the 2019 projected emission rates include the additional control devices and were used in the NAAQs attainment modeling. The data therefore used in the NAAQs attainment modeling is as follows:

2008

PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	NH_3
131.73	84.55	14.19	111.74	11.68	132.73	0.97

2014

PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	NH_3
174.56	112.04	18.80	148.08	15.48	175.89	1.29

2017

PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	NH_3
198.30	127.27	21.35	168.21	17.58	199.81	1.46

2019

PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	NH_3
205.09	117.42	23.30	142.50	19.18	217.97	1.59

H-180 [EPA]: Condensable PM is not accounted for in the RACT Evaluation Report or in the proposed PM emission limit in draft SIP subsection IX.H.12.f. of 0.12 lbs/ton of stone feed. The SIP subsection does not indicate whether stack testing needs to include condensable PM. Please explain why condensable PM is not accounted for. See our related General Comment #5 on condensable PM above. Please also explain why the proposed emission limit is expressed as PM rather than $PM_{2.5}$. The table provided to us on October 31, 2013 indicates that the emissions inputted to modeling were 117.42 tpy of $PM_{2.5}$· How does this relate to the proposed emission limit of 0.12 lbs. of PM per ton of stone feed?

Response to H-180: UDAQ will require a PM condensable limitation and a $PM_{2.5}$ emission limitation as well as PM condensable and $PM_{2.5}$ stack testing requirement prior to plant start-up. This will be required through the UDAQ permitting process and an Approval Order/Title V permit modification for this activity. Therefore, the requirements addressed would be covered through the permitting process and are not necessary for the $PM_{2.5}$ SIP process.

Additionally, the proposed emission limitation of 0.12 lbs of PM per ton of stone fed comes directly from 40 CFR 63 Subpart AAAAA National Emission Standards for Hazardous Air Pollutants for Lime Manufacturing Plants. This requirement is considered RACT and again as stated above, a PM2.5 emission limitation and stack testing will be required to establish the appropriate PM2.5 emission limitation.

H-181 [EPA]: Stack testing is proposed to be required at a minimum of every five years. We are concerned with stack test frequencies longer than one year. Please explain why these test frequencies are sufficient to ensure continuous compliance with the limits.

Response to H-181: Stack testing frequency is based on engineering judgment and the permit writer’s knowledge regarding the specific sources process and history. How close a source is to a threshold (significance, PSD, etc.), what existing stack requirements are in place, and whether the equipment is controlled with industry wide accepted technology are some things considered when setting testing frequency. If the analysis by the engineer revealed a need for annual sampling it would have been required.

HEXCEL CORPORATION: SALT LAKE OPERATIONS

H-182 [EPA]: Draft SIP subsection IX.H.12.i. proposes a plant wide limit on daily natural gas consumption and a plant wide limit on daily carbon fiber production. Page 5 of the RACT Evaluation Report indicates, however, that "existing controls" consist not only of a plant wide carbon fiber production limit and a natural gas consumption limit (the latter for NOx and S02 control), but also a plant wide VOC emission limit, along with various operational controls on incinerators/ovens. Please explain why no plant wide VOC emission limit or operational controls on the incinerators/ovens are proposed as RACT requirements.

Response to H-182: By limiting natural gas combustion and total production, emissions are automatically limited. The only sources of VOC emissions at Hexcel are combustion and fiber production.

Individual control methodologies are not being included as specific requirements in the language of the SIP as this unnecessarily limits both the source and the agency from including better, higher efficiency controls, should such become available. In this case UDAQ is including the two limitations that directly restrict total VOC emissions on a source-wide basis. In this way, UDAQ ensures that RACT emission reductions are achieved without binding the source unnecessarily. See previous responses relating to individual emission controls (H-52, 53).

H-183 [EPA]: The RACT Evaluation Report also identifies continued use of incinerators as RACT for VOC control at Fiber Lines 2-8 and 10-12, the Pilot Plant, and the Matrix Operations. The current NSR permit (Approval Order) dated December 28, 2011, specifies minimum operating temperatures and residence times for the incinerators. Please explain why a requirement for continued use of these incinerators for VOC control, with appropriate operational parameters, is not included as proposed RACT in draft SIP subsection IX.H.12.i. Also, the RACT Evaluation Report also indicates that Fiber Lines 13 and 14 currently are permitted with a baghouse for PM control, the use of ultra-low NOx burners for NOx control, and use of a Regenerative Thermal Oxidizer (RTO) for VOC emission control. The Report identifies these controls as RACT for PM2.5, NOx and VOC at Fiber Lines 13 and 14. The current NSR permit (Approval Order) dated December 28, 2011, specifies operational requirements for the baghouse and RTO at these fiber lines. Please explain why no emission limits or requirements for PM2.5, NOx or VOC controls are proposed in subsection IX.H.12.i. as RACT requirements at Fiber Lines 13 and 14.

Response to H-183: DAQ would point to its federally approved NSR permitting program and its role as a required element (from 172(c)(5)) of these plan provisions. The approval orders issued as a consequence of this program offer a repository for the many emission limitations that would not rise to the level of importance compelled by the SIP. The DAQ also has a minor source permitting program, and a BACT analysis is required for minor sources and for major sources that are below significance. Collectively, these limits and the NSR rules and regulations that prescribe them, are part of a control strategy that is adequate for timely attainment of the PM2.5 NAAQS.

OLYMPIA SALES

H-184 [EPA]: With regard to $PM_{2.5}$ control, page 5 of the RACT Evaluation Report indicates that Olympia Sales plans to install, within the next year, a baghouse for PM control from the woodworking shop, to replace the existing cyclones. Page 8 identifies RACT for $PM_{2.5}$ as installation of the baghouse. The RACT Summary Table indicates that the expected emission reduction due to baghouse installation will be 7.5 tpy for PM10 and 4.4 tpy for PM2.5. The only proposed RACT requirement in draft SIP subsection IX.H.12.p., however, is installation and operation of the baghouse by January 1, 2015. No emission allowable is proposed for $PM_{2.5}$. If Olympia Sales is being credited with an emission reduction due to installation of a new baghouse, then this needs to be reflected as proposed RACT in the SIP with a proposed emission limit for $PM_{2.5}$.

Response to H-184: The baghouse installation proposed in the UDAQ RACT analysis for Olympia Sales Company results in an emission rate of 4.4 tpy of $PM_{2.5}$ being emitted from the sawing, cutting, and sanding areas in the cabinet manufacturing plant. Because this activity is intermittent and does not occur consistently throughout the plant operation; it is not deemed necessary to require a $PM_{2.5}$ emission limitation and an associated $PM_{2.5}$ stack testing requirement. Additionally, UDAQ does not currently implement stack testing requirements on sources of $PM_{2.5}$ with potential emission rates less than 10 tpy.

H-185 [EPA]: With regard to VOC control, page 7 of the RACT Evaluation Report indicates that recent revisions to the wood furniture MACT will require Olympia Sales to cut the amount of VOC in their topcoats and sealers almost in half by January of 2015. Page 8 identifies RACT for VOC as continued research and implementation on the use of low VOC coating and waterbased coatings. The current NSR permit (Approval Order) dated April 13, 1995, requires use of High Volume Low Pressure (HVLP) spray guns for all painting processes. However, draft SIP subsection IX.H.12.p. does not propose any RACT requirements for VOC. Please explain why this is not included.

Response to H-185: The requirement for use of HVLP spray guns was initiated in Approval Order DAQE-300-95 dated April 13, 1995 as a BACT requirement. As it is required as part of this AO then it was not deemed necessary as a SIP RACT requirement.

H-186 [EPA]: Page 1 of the RACT Evaluation Report indicates that the plants assumed operation will be similar to that of the past five years. Page 2 indicates that 2008 actual emissions were 4.28 tons for PM2.5 and 20.88 tons for VOC. The table provided to us on October 31, 2013 indicates that the emissions used for NAAQS attainment modeling were 0.0279 tpy for PM2.5 and 15.66 tpy for VOC. Please explain whether the expected installation of a baghouse accounts for the $PM_{2.5}$ reduction from 2008 actual emissions and whether compliance with MACT accounts for the VOC reduction from 2008 actual emissions. If Olympia Sales is being credited with a VOC reduction due to MACT compliance, then this needs to be reflected in proposed RACT requirements in draft SIP subsection IX.H.12.p. Similarly, as we stated above, if Olympia Sales is being credited with a $PM_{2.5}$ emission reduction, then this needs to be reflected in terms of a proposed $PM_{2.5}$ emission limit for the new baghouse.

Response to H-186: The 2008 actual emissions provided in the Salt Lake County $PM_{2.5}$ SIP demonstration do not include the installation of the baghouse and reduction due to the wood furniture MACT which will be imposed upon Olympia Sales. The 2008 actual emissions are as follows:

2008

PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	NH_3
7.66	4.28	0.0018	0.32	20.88	0.27	0.0014960

NAAQS attainment modeling provided for the year 2014 included the installation of a baghouse. The modeled emissions included were as follows:

2014

PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	NH_3
0.031	0.028	0.0018	0.32	20.88	0.27	0.0014960

NAAQS attainment modeling provided for the projected year 2017 included the baghouse and a reduction in VOC emission due to the wood furniture MACT requirement. The modeled emissions included were as follows:

2017

PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	NH_3
0.0313	0.028	0.0018	0.32	15.66	0.27	0.0014960

H-187 [EPA]: Please explain how the emissions used for NAAQS attainment modeling compare to the emissions that are proposed to be allowed, on a plant wide daily basis. The table provided to us on October 31, 2013 lists emission figures in tons/year that were used for modeling. The basis for these figures (e.g., projected actuals, proposed allowables, 90% of PTE, or possibly something else) is not indicated. Our objective here is to see if there is a substantial difference between the proposed allowable emissions and the emissions used for modeling.

Response to H-187: As demonstrated in a previous response to EPA Comment for Olympia Sales Company, the emissions used for NAAQS attainment modeling were based upon projected actuals, implementing the installation of the baghouse and new MACT requirements for wood furniture.

PACIFIC STATES CAST IRON PIPE COMPANY (PSCIPCO)

H-188 [EPA]: Draft SIP subsection IX.H.l3.d. indicates that low NOx burners (LNB) with flue gas recirculation (FGR) technology shall be required to be in operation on the Annealing Oven by January 1, 2017. This is identified as RACT on page 7 of the RACT Evaluation Report. It is not clear why page 6 of the Report indicates that the current NOx emission rate for the Annealing Oven at PSCIPCO (3.98 lb/hr and 0.098 lb/MMBtu), without L Band FOR, is about the same as the emission rates for "annealing furnaces" at other facilities where LNB + FGR has already been installed (4 .34 lb/hr and 0.095 lb/MMBtu). This would seem to imply that addition of LNB + FGR at PSCIPCO would not get much NOx reduction, if any. However, the RACT Summary Table indicates an expected reduction at PSCIPCO of 11.9 tpy of NOx. Please explain how that amount of expected reduction was estimated.

Response to H-188: The expected reduction is actually listed at 11.1 tpy, not 11.9 tpy in the PSCIPCO RACT Analysis. Section 2.1 of the RACT analysis lists 2008 actual emissions as 13.35 tpy. Applying an 83% reduction efficiency (as shown in the table in that section "NOx Technically Feasible Control Option Cost Analysis Annealing Oven") results in a11.1 tpy removal of NOx from the use of LNB & FGR.

H-189 [EPA]: Draft SIP subsection IX.H.13.d. does not propose any NOx emission limit or minimum required NOx control efficiency at the Annealing Oven after installation of LNB + FOR. If the plant is being credited with a NOx emission reduction due to new controls (11.9 tpy, cited above), then this needs to be reflected in proposed RACT requirements for NOx in draft SIP subsection IX.H.13 .d., in terms of an emission limit or control efficiency, with appropriate testing requirements to determine compliance.

Response to H-189: As stated above, the reduction is 11.1 tpy. In addition, the technology is FGR not "FOR". However, based on other comments received, the retrofitting of the annealing oven with LNB + FGR has been determined to not be economically feasible. RACT for the control of NOx at the annealing oven has now been determined to be GCP and a limit of 63.29 MMBtu/hr. The 63.29 MMBtu/hr has been included as a limit for PSCIPCO.

H-190 [EPA]: Draft SIP subsection IX.H.13 .d. proposes to require installation of a 95% efficient thermal oxidizer by January 1, 2018, to control VOC emissions from Painting Operations. The RACT Summary Table proposes to credit the oxidizer with a 129.1 tpy VOC reduction. The draft SIP subsection indicates that compliance with the efficiency requirement shall be determined "using a method acceptable to the Director." This language is a form of director discretion that undermines federal enforceability of the SIP. The language should be revised to specify a test method for VOC, or else subsection IX.H.11.e should be revised to specify a test method for VOC and this subsection would then cross-reference it.

Response to H-190: Based on other comments the thermal oxidizer was determined not to be economically feasible. RACT for the painting operations is a source wide VOC limit of 118.66 tpy.

The DAQ agrees with the testing method comment. The language has been changed to require the use of "EPA-approved testing methods acceptable to the Director".

H-191 [EPA]: The RACT Summary Table indicates that LNB & FGR will be installed for NOx control at the Annealing Oven by 2017, and that thermal regenerative oxidation will be installed for VOC control at the Painting Operations by 2019. Please explain why earlier dates would not be achievable.

Response to H-191: Based on other comments, both the LNB & FGR and the thermal oxidizer were determined not to be economically feasible. RACT for the annealing oven is GCP with a maximum heat rating of 63.29 MMBtu/hr. RACT for the painting operations is a source wide VOC limit of 118.66 tpy.

H-192 [EPA]: Draft SIP subsection IX.H.l3.d. indicates that a VOC limit for the thermal oxidizer controlling the painting operations shall be established in the Approval Order (AO) by no later than January 1, 2019. As we have noted in other instances, this approach is not approvable. RACT limits need to be specified in the SIP, not determined at a future date or specified in an AO.

Response to H-192: Based on RACT comments, the thermal oxidizer was determined not to be economically feasible. RACT for the painting operations is a source wide VOC limit of 118.66 tpy.

H-193 [EPA]: The table provided to EPA on October 31, 2013 indicates that the emissions used for NAAQS attainment modeling were the 2008 actual emissions. The RACT Evaluation Report does not indicate what those emissions were for NOx and VOC (the pollutants emitted in greatest quantity from PSCIPCO). Please explain what the actual 2008 plant wide NOx and VOC emissions were, and what the allowed plant wide emissions are estimated to be after application of RACT, on a daily basis. Our objective here is to see If there is a substantial difference between the proposed RACT allowable and the emissions used for modeling.

Response to H-193: The commenter is incorrect, Section 2.1 of the RACT analysis indicates the 2008 actual (21.6 tpy) and existing allowable NOx emissions for the annealing oven. The existing allowables for NOx emissions at the annealing oven are directly tied to production, which are limited to 3 pieces of product per day and 350 pieces of product per 12-month period. These production limits equate to an approximate NOx potential of 34.85 tpy. In addition, Section 2.4 of the RACT analysis indicates the 2008 actual (56.59 tpy + 52.86 tpy) and existing allowable (260 tpy) VOC emissions from the painting operations.

ATK LAUNCH SYSTEMS INC. – PROMONTORY

H-194 [EPA]: None of the provisions identified as RACT controls in the RACT Evaluation Report are reflected as proposed RACT in draft SIP subsection IX.H.12.a. Page 4 of the Report identifies RACT for NOx as replacement of the burners at the two largest boilers (each rated at 71.1 MMBtulhr) with LNB + FGR. Page 5 identifies RACT for VOC as the current practice of using low VOC and/or low vapor pressure solvents, the storing of VOC emitting material in closed containers, and practices to prevent spills. Page 8 identifies RACT for PM2.5, S02, NOx and VOC as increased waste minimization efforts to reduce open burning, and notes that ATK has a waste minimization program in place. Please explain why none of these selected RACT controls in the RACT Evaluation Report are reflected as proposed RACT in draft SIP subsection IX.H.12.a.

Response to H-194: Individual control methodologies were not included as specific requirements in the language of the SIP as this unnecessarily limits both the source and the agency from including better, higher efficiency controls, should such become available. By electing to require only a final emission limitation for these sources to maintain, UDAQ ensures that equivalent emission reductions are achieved without binding the source unnecessarily.

H-195 [EPA]: The RACT Summary Table projects a 9.24 tpy reduction in NOx emissions resulting from installation of LNB + FGR at the two 71 MMBtu/hr boilers. If ATK is being credited with a NOx reduction due to installation of new controls as RACT, then this needs to be reflected as proposed RACT in draft SIP subsection IX.H.12.a. The draft SIP subsection does not currently propose any controls for these boilers.

Response to H-195: The limits for the boilers will be included in subsection IX.H.12.a.iv

The boilers operated as Building M576 will be upgraded with LNB with FGR unless restricted or replaced. Total NOx emission from the M576 replacement boilers shall not exceed 6 tons/year. The emission restriction is effective starting January 1, 2017.

H-196 [EPA]: The RACT Summary Table indicates that LNB and FGR will be installed at the 71 MMBtu/hr boilers for NOx control by 2017. Please explain why an earlier date would not be achievable.

DAQ Response: ATK is currently determining if they will upgrade the boilers or replace them with smaller boilers that are located closer to the buildings utilizing the steam. ATK has stated that they will not be able to accomplish this before 2017.

H-197 [EPA]: Please explain how the emissions used for NAAQS attainment modeling compare to the emissions that are proposed to be allowed, on a plantwide daily basis. The table provided to us on October 31 , 2013 does not include ATK, therefore we have no information on what emissions basis was used for modeling (e.g. , projected actuals, proposed allowables, 90% of PTE, or possibly something else) and how that compares to the emissions that are proposed to be allowed.

Response to H-197: The emissions are based on the 2008 emission inventory. The modeled emissions reflect the baseline emissions plus applicable growth factors, minus reductions from RACT.

H-198 [ATK]: ATK submitted comments to clarify the limits in Section IX Part H.12, and to add a requirement for the boilers in Building M576.

Response to H-198: The requested changes by ATK are acceptable and will be implemented as shown below.

a. *ATK LAUNCH SYSTEMS INC – Promontory Point*

   i. *During the period November 1 to February 28 annually, open burning 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 on days when the 24-hour average $PM_{2.5}$ levels exceed 35 ug/m3 at the nearest real-time monitoring station. During this period, records will be maintained identifying the quantity opened burned and the 24-hour average $PM_{2.5}$ level at the nearest real-time monitoring station on days when open burning occurs.*

   ii. *During the period November 1 to February 28 annually, on days when the 24-hour average $PM_{2.5}$ levels exceed 35 ug/m3 at the nearest real-time monitoring station, the following shall not be tested:*

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

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

         I. *A single test of rocket motors less than 1,000,000 lbs. of propellant per motor is allowed on a day when the 24-hour average $PM_{2.5}$ level exceeds 35 ug/m3 at the nearest real-time monitoring station provided notice is given to the Director of the Utah Air Quality Division. No additional tests of rocket motors less than 1,000,000 lbs. of propellant may be conducted during the inversion period until the 24-hour average $PM_{2.5}$ level has returned to a concentration below 35 ug/m3 at the nearest real-time monitoring station.*

   iii. *During this period, records will be maintained identifying the size of the rocket motors tested and the 24-hour average $PM_{2.5}$ level at the nearest real-time monitoring station on days when motor testing occurs.*

   iv. *After January 1, 2017, ATK shall either upgrade the two 71 MMBTU/hr boilers operated in Building M576 so that they have a NO_x emission rate not greater than 30 ppm or replace them with boilers that have a NO_x emission rate less than 30 ppm.*

H-199 [EPA]: Draft SIP subsection IX.H.12.a indicates that the proposed RACT provisions for A TK consist solely of limits on the pounds of reactive waste, reactive compounds, and rocket motor propellants that may be open burned or tested "when the PM2.5 levels exceed 35 ug/m3 at the nearest real-time monitoring station," during winter months (November through February). In our November 1, 2012 comments on an earlier draft of the PM2.s SIP, we stated that these proposed provisions are inconsistent with the CAA and EPA's regulations on dispersion techniques and intermittent control systems (40 CFR 51.118 and 51.119) and are not creditable for purposes of demonstrating attainment or meeting RACT requirements. They are not a substitute for continuous emissions limits/controls. Also, in effect, these provisions treat the area around A TK as an independent nonattainment area. Regarding the proposal to apply the requirements on a seasonal basis, EPA is evaluating whether this is an acceptable approach to address PM2.s under the CAA. No emission controls, or efforts to minimize the above-mentioned open burning or testing, or to investigate alternatives to open burning or testing, such as waste minimization, other means of disposal, or transporting the materials somewhere outside the nonattainment area before burning or testing, are proposed. The proposed provisions do not appear to be based on a RACT analysis, nor is it clear whether these provisions represent a reduction from 2008 baseline emissions. It is also not clear what pollutant(s) these provisions are intended to address. It is also not clear why certain provisions only apply to rocket motors less than 1,000,000 lbs. of propellant per motor and larger motors are not addressed.

Response to H-199: Except for the 1,000,000 lb motors, the comments made by EPA above are addressed in the RACT Evaluation Report. When the motors > 1,000,000 lbs are tested, the exit velocities and temperatures causes the resultant plume to rise to an altitude of 10,000 ft, which is above the inversion zone. Modeling has shown that the plume does not impact the Wasatch front nonattainment area.

H-200 [Wasatch Clean Air Coalition (WCAC)]: General Condition B. During the period November 1 to February 28 annually, on days when the PM2.5 levels exceed 35 ug/m3 at the nearest real-time monitoring station, the following shall not be tested:... The commenter suggests the language to be modified to match the language mandatory no-burn language proposed in R307-302-3(4). When the ambient concentration of PM2.5 measured by are forecasted to reach or exceed 25 micrograms per cubic meter, the director will issue a public announcement to provide broad notification that a mandatory no-burn period.

ATK should not be allowed to test propellant, energetics, pyrotechnics, flares and other reactive compounds or fire rocket motors during inversions.

Response to H-200: The DAQ disagrees with the comment. The rules in R307-302 apply to residential burning. The SIP implementation guidance provides a definition of RACT. The rules for SIP development specifically state that a RACT analysis that the DAQ determines as unreasonable because it would result in measures that are ``absurd, unenforceable, or impractical" or that would cause ``severe disruptive socioeconomic impacts, such as requirements to re-locate industry or curtail production, cannot be required.

ATK has voluntarily agreed to restrict their testing during the periods that $PM_{2.5}$ levels are above the NAAQS.

H-201 [WRA]: Although this facility is a significant source of direct PM2.5 emissions, as well as NOX and VOCs, almost no controls are being required at the facility and indeed direct PM2.5 emission will increase at the facility as of 2019. This reflects insufficient RACT. For example, there appear to be no controls on testing rocket motors of more than 1 million pounds and no estimates of the emissions from such testing. As a result, there is no basis for claiming that RACT has been met for testing of these rocket motors.

Moreover, to restrict testing of rocket motors of less than 1 million pounds only when concentrations of PM2.5 have already exceeded the NAAQS undermines efforts to reduce emissions and achieve the NAAQS as expeditiously as practicable. Rather, any open burning at ATK should be prohibited whenever inversions are predicted or underway – or alternatively, when PM2.5 concentrations are above 15 ug/m3.

In addition, the proposed provisions consist solely of limits on the pounds of reactive waste and rocket motor propellants that may be burned “when the PM2.5 levels exceed 35 ug/m3 at the nearest real-time monitoring station.” These appear to be new provisions that are not in any existing state rules or NSR permits applicable to ATK. These proposed provisions are inconsistent with the CAA and EPA’s regulations on dispersion techniques and intermittent control systems (40 CFR 51.118 and 51.119) and are not creditable for purposes of demonstrating attainment or meeting RACT requirements. They are not a substitute for continuous emissions limits/controls. Also, in effect, these provisions treat the area around ATK as an independent nonattainment area.

The costs of minimizing open burning, alternatives to open burning, such as waste minimization or transporting the materials somewhere outside the nonattainment area before burning, lack an objective basis in the record and emission reductions achieved as a result of these alternatives is not evident. This is particularly important given that the cost per ton analysis must be based on emissions reductions achieved. The proposed provisions do not appear to be based on a RACT analysis nor is it clear whether these provisions represent a reduction from 2008 baseline emissions. It is also not clear what pollutant(s) these provisions are intended to address. A meaningful RACT analysis is required for ATK.

Response to H-201: With respect to these comments on RACT, UDAQ thanks the commenter for the comment. While final RACT determinations were made at the December 4, 2013 meeting of the Utah Air Quality Board when it voted to accept SIP Subsection IX.A.21: Control Measures for Area and Point Sources, Fine Particulate Matter, PM2.5 SIP for the Salt Lake, UT Nonattainment Area and SIP Subsection IX.A.22: Control Measures for Area and Point Sources, Fine Particulate Matter, PM2.5 SIP for the Provo, UT Nonattainment Area, UDAQ anticipates the need to submit a new BACT/RACT analysis as part of a Subpart 4 Serious PM2.5 Nonattainment Area SIP in the near future, and would invite the commenter to resubmit these comments at that time.

NUCOR STEEL MILLS

H-202 [EPA]: Please explain how the emissions used for NAAQS attainment modeling compare to the emissions that are proposed to be allowed, on a plantwide daily basis. The table provided to us on October 31, 2013 indicates that projected actual emissions were used as the basis for modeled emissions. The RACT Evaluation Report provides some information on 2008 actual annual emissions for portions of the plant, but we are unable to determine what the emissions were for the overall plant on a daily basis. Also, we are unable to determine from draft SIP subsection IX.H.12.o. how much emissions are proposed to be allowed for the overall plant on a daily basis. Our objective here is to see if there is a substantial difference between the proposed allowable emissions and the emissions used for modeling.

Response to H-202: It was not intended to have Section IX.H.12.o contain emissions for the overall plant on a daily basis. Most of the sources listed in Section IX.H.12 and 13 do not contain emissions for the overall plant listed. Section IX.H.12.o contains limits for the significant emission points and not the insignificant emission points.

For existing and smaller emission units, the DAQ would point to its federally approved NSR permitting program and its role as a required element (from 172(c)(5)) of these plan provisions. The approval orders issued as a consequence of this program offer a repository for the many emission limitations that would not rise to the level of importance compelled by the SIP. The DAQ also has a minor source permitting program, and a BACT analysis is required for minor sources and for major sources that are below significance. Collectively, these limits and the NSR rules and regulations that prescribe them, are part of a control strategy that is adequate for timely attainment of the PM2.5 NAAQS.

H-203 [EPA]: Page 8 of the RACT Evaluation Report says that "Based on the consent decree, Reheat furnace #1 and Reheat furnace #2 constitute RACT." Please be aware that there is no provision in the Clean Air Act for consent decrees to constitute RACT. Since the consent decree apparently required a "thorough evaluation of possible NOx controls for reheat furnaces," then that evaluation should be presented in the RACT Evaluation Report, or at least a summary of that evaluation, rather than just a statement about EPA's conclusion of the study. EPA made no conclusion from the study that constituted RACT. The RACT Evaluation Report does not explain what possible NOx controls were considered, nor why 0.07 lb/MMBtu should constitute NOx RACT for new reheat furnaces, nor why 0.09 lb/MMBtu should constitute NOx RACT for retrofit furnaces.

Response to H-203: The results of the analysis from the consent decree resulted in controls that had a higher level of control than most of the sources listed in the RBLC.

H-204 [EPA]: Draft SIP subsection IX.H.12.o. proposes a NOx emission limit for the Electric Arc Furnace (EAF) Baghouse of "59.75 lbs/hr (12-month rolling average)." Please explain how a 12-month rolling average can represent RACT in a plan that is intended to attain a 24-hour NAAQS.

Response to H-204: The NO_x and SO_2 emissions are measured by a CEM and the EAF operates on a continuous basis with very small variations in its operations. Hourly emission rates were modeled and this demonstrates compliance. All RACT limits were initially determined based on protection of the 24-hour standard. However, reporting requirements, based on a 24-hour limit, would have been excessive and in some cases, impossible. The limits incorporated into the SIP represent the best scenario for determining compliance with the limit that has been extrapolated from a shorter term limit that is protective of the $PM_{2.5}$ NAAQS 24-hour standard

H-205 [EPA]: Draft SIP subsection IX.H.12.o. does not specify an averaging time or a stack test method for the proposed NOx emission limits at Reheat Furnaces #1 and #2, nor for the proposed VOC emission limit at the EAF Baghouse. Draft SIP subsection IX.H.11.e. should be cross-referenced for stack test methods, as was done for other sources (e.g., Central Valley Water Reclamation; Chemical Lime), and an averaging time specified for the emission limits.

Response to H-205: These limits are not averaged and are instantaneous hourly limits.

H-206 [EPA]: Stack testing at the EAF Baghouse for VOC is proposed to be required once every five years and stack testing at the Reheat Furnaces for NOx is proposed to be required once every three years. We are concerned with stack test frequencies longer than one year. Please explain why these test frequencies are sufficient to ensure continuous compliance with the limits.

Response to H-206: Stack testing frequency is based on engineering judgment and the permit writer's knowledge regarding the specific sources process and history. How close a source is to a threshold (significance, PSD, etc.), what existing stack requirements are in place, and whether the equipment is controlled with industry wide accepted technology are some things considered when setting testing frequency. If the analysis by the engineer revealed a need for annual sampling it would have been required.

H-207 [WRA]: The proposed PM2.5 emission limits for the EAF baghouse are not RACT as they represent emission limitations established in 1999. The filterable PM10 emission limit in the current NSR permit is 20.06 lbs/hr. This limit has been in effect in AOs dating back to July of 1999. The proposed limit for filterable PM2.5 is only slightly lower and therefore is not RACT. The NOX limit must be averaged over a period no longer than 24-hours.

Response to H-207: With respect to comments on RACT, UDAQ thanks the commenter for the comment. While final RACT determinations were made at the December 4, 2013 meeting of the Utah Air Quality Board when it voted to accept SIP Subsection IX.A.21: Control Measures for Area and Point Sources, Fine Particulate Matter, PM2.5 SIP for the Salt Lake, UT Nonattainment Area and SIP Subsection IX.A.22: Control Measures for Area and Point Sources, Fine Particulate Matter, PM2.5 SIP for the Provo, UT Nonattainment Area, UDAQ anticipates the need to submit a new BACT/RACT analysis as part of a Subpart 4 Serious PM2.5 Nonattainment Area SIP in the near future, and would invite the commenter to resubmit this comment at that time.

H-208 [WRA]: The proposed SO2 emission limits for the EAF baghouse include 3-hour and daily average limits from the current AO. These limits appear to be less stringent that the limit in the current AO. The proposed provisions do not include any short-term NOX emission limits for the EAF baghouse. Because this proposed limit is equivalent to 262 tons per year, it is less stringent than the limit of 245 tons per rolling 12-month period in the current AO and therefore is not RACT.

Response to H-208: Nucor recently received a new AO which included an increase in SO2 emissions. The limits in the SIP accurately reflect SO2 limits. Recordkeeping and reporting requirements are found in the Title V Permit.

H-209 [WRA]: The proposed VOC emission limit of 22.2lb/hr is carried over from the current NSR permit and therefore does not appear to represent a reduction from 2008 baseline missions or qualify as RACT. The proposed provisions also lack recordkeeping and reporting requirements. Stack testing every three or five years is not RACT and fails to ensure that the emission limitations are enforceable.

Response to H-209: Nucor recently received a new AO which included an increase in VOC emissions. The limits in the SIP accurately reflect VOC limits. Recordkeeping and reporting requirements are found in the Title V Permit.

NUCOR (VULCRAFT DIVISION) VULCRAFT/NUCOR BUILDING SYSTEMS

H-210 [EPA]: The table provided to EPA on October 31, 2013 indicates that NAAQS attainment modeling was based on emissions that are "90% of PTE" and that the proposed RACT allowable emissions are also "90% of PTE." Draft SIP subsection IX.H.12.u. lists a proposed RACT emission allowable for VOC of 305.07 tons per rolling 12-month period. We note that this is 90% of the allowable in the current NSR permit (Approval Order), which is 338.97 tons per rolling 12-month period. Please explain how it was determined that application of low-VOC paint results in a calculation of 305.07 tons of VOC per rolling 12-month period as RACT. This is not explained in the RACT Evaluation Report. Please also explain how a rolling 12-month emission limit can represent RACT in a plan that is intended to attain a 24-hour NAAQS.

Response to H-210: Nucor Building Systems (NBS) is a new source. As a new source (in operation less than two years), the NAAQS attainment demonstration used an input of 90% of VOC PTE. As the commenter has already pointed out, the current AO for the source lists the VOC PTE as 338.97 tpy. Taking 90% of this value yields the result of 305.07 tons listed above. This evaluation was applied generally to most new sources or new emission units. With respect to the rolling 12-month emission limit, NBS is a VOC source based on painting emissions. Daily tracking and calculation of VOC emissions represents an unreasonable burden on a source of this type. VOC emissions from painting and solvent use are most easily tracked from inventory usage, and not from direct measurement of container volumes. Inventory tracking is standardized across the industry on a monthly basis, and the retention and retrieval of these records represents the most logical methodology for calculation of VOC emissions.

H-211 [EPA]: Page 6 of the RACT Evaluation Report says R307-350 requires the use of low-VOC paint and identifies the requirement as RACT. The Report says the requirement under R307-350 is to use paint at Vulcraft with less than 2.8 lbs/gallon VOCs, and to use paint at Nucor Building Systems with less than 2.3 lbs/gallon VOC, unless the products are air-dried, in which case less than 2.8 lbs/gallon must be used. However, draft SIP subsection IX.H.12.u. says only that R307-350 applies to Vulcraft. Please explain why the specific limits in R307- 350 are not cited as RACT in draft SIP subsection IX.H.12.u.

Response to H -211: IX.H.12.u.i states that R307-350 applies to Vulcraft and Nucor Building Systems. UDAQ has not included the specific requirements of R307-350 in Section IX.H.12.u.i as this would be redundant.

H-212 [EPA]: Page 5 of the RACT Evaluation Report says "It is not technically feasible to construct a collection system at every degreaser" to capture and control VOCs. No analysis was provided to support this conclusion. Facilities frequently do install such collection systems. Please explain further.

Response to H-212: The reasons for not requiring the installation of these controls are outlined in the RACT Evaluation Report for Vulcraft/NBS.

H-213 [EPA]: The draft SIP needs to specify a means to determine compliance with the emission limit.

Response to H-213: UDAQ agrees with the comment. SIP Section IX.H.12.u.ii will be modified to include an additional sentence which specifies that *VOCs emissions shall be calculated from paint and solvent usage based on inventory records.*

H-214 [Vulcraft]: Vulcraft submitted comments on the SIP process and nonattainment area designation.

DAQ Response: These comments were addressed in the Part A.21 and A.22 SIP comment period. The comments are noted and no further response is required.

KENNECOTT (KUC) – BINGHAM CANYON MINE/COPPERTON CONCENTRATOR

H-215 [EPA]: Page 5 of the RACT Evaluation Report identifies NOx RACT for haul truck tailpipe emissions as "replace all trucks that are older than 14 years with trucks that have the highest tier rating available and that in the future as trucks are replaced, the replacements use the highest tier engine available." The Report explains that the higher tier engines have lower NOx emissions in grams per horsepower-hour. However, draft SIP subsection IX.H.l2.l. does not propose any such requirement. Instead, the only proposed requirement pertaining specifically to haul trucks is a limit of 30,000 miles of haul truck use per calendar day. This choice of a truck mileage limit as a representation of RACT is not reflected in the RACT Evaluation Report. Please explain why the proposed RACT requirement pertaining to the haul trucks does not resemble the discussion in the RACT Evaluation Report.

Response to H-215: The control is reflected in the combined NOx, SO2, PM2.5 limit. The decrease in emissions from 6,205 tons to 5,585 tons will be achieved through the replacement of truck engines with higher tiered engines.

H-216 [EPA]: The RACT Summary Table indicates that higher tier engines will be used in haul trucks for NOx control by 2019 and credits Kennecott with a 64.7 tpy NOx reduction. For additional reductions such as this to be creditable in the attainment demonstration, a requirement to achieve such reductions needs to be reflected in the SIP. Please explain why this was not done. Please also explain why an earlier date would not be achievable. Page 5 of the RACT Evaluation Report says that if the four tier 1 trucks that are older than 2005 were replaced now, that would reduce the emissions by 64.7 tpy. Page 9 of the Report says that "Requiring KUC to replace the model year 2004 haul trucks with trucks that have the highest tier rating available will reduce NOx emissions by a minimum of 64.7 tpy. This will begin in 2018 with complete reduction by 2018. In 2019 the six 2005 model year trucks will begin replacement by 2019 but the replacement will not be complete until the end of 2019." Please explain why the 64.7 tpy emission reduction in the RACT Summary Table is not proposed to occur until 2019. From the RACT Evaluation Report, it appears that reductions beyond the 64.7 tpy reduction cited in the RACT Summary Table might occur by 2019.

Response to H -216: The reason for the implementation date of 2019 is explained in the RACT Evaluation Report. These engines are still under development and are not readily available, and require large capital investments with significant lead times. This date was reached through negotiation with the source.

H-217 [EPA]: Draft SIP subsection IX.H.12.l. proposes to limit sourcewide emissions to 6,205 tons per rolling 12-month period, for NOx, PM2.5 and S02 combined, until January 1, 2019. After that date, sourcewide emissions are proposed to be limited to 5,585 tons per rolling 12-month period. No rolling 12-month emission limits are proposed in the RACT Evaluation Report. Please explain how rolling 12-month limits can represent RACT in a plan that is intended to attain a 24-hour NAAQS. Please also explain how these proposed limits were calculated and whether they have any relationship to the proposed mileage limit of 30,000 miles per day of haul truck use.

Response to H-217: The BCM operates 8760 hours per year and there is very little change in operations on a day to day basis. The mileage limit is incorporated to protect the 24-hour standard. Therefore, this limit on the combined $PM_{2.5}$, NO_x and SO_2 per 12-month rolling average protects the daily NAAQS.

H-218 [EPA]: The provisions in the draft SIP are not adequate to ensure the enforceability of the specified measures. For example, the draft does not specify means to determine compliance with the 30,000 mile calendar day limit. Regarding the source-wide combined NOx, PM2.5 and S02 limits, the draft SIP states that compliance will be determined "per methodology outlined in the Emission Inventory." It is unclear what this means, and it is not sufficient to ensure the limits could be enforced, even assuming a 12-month averaging period would be sufficient.

Response to H-218: The 30,000 mile limit is in the EPA approved 1994 PM_{10} SIP and was carried over into the $PM_{2.5}$ SIP. The mechanism for enforcement is in the current Approval Order.

H-219 [EPA]: We are also concerned with the specification of a combined limit for the three pollutants and require an explanation how this is sufficient given the differing impacts of the three pollutants on ambient $PM_{2.5}$ levels.

Response to H-219: PM2.5 is a direct contributer, In Appendix S EPA has designated SO_x as a precursor and it has been shown in the PM2.5 SIP application and the EPA approved PM10 SIP that NOx is a precursor to the PM2.5 nonattainment status.

H-220 [EPA]: The provisions to address fugitive dust are vague and practically unenforceable. What does the phrase "as conditions warrant" mean? The draft language does not explain. Greater specificity is needed. What is "the pit influence boundary?" The draft language does not define this phrase. What does it mean to require, as one possible measure, "ensure the surface of the active haul roads located within the pit influence boundary consists of ... chemical dust suppressant?" Isn' t chemical dust suppressant something applied to the surface of the haul roads? What does the phrase "shall be the primary means" mean? Is it possible to specify that the ore conveyors shall be used to transport all crushed ore from the mine to the concentrator? Or at least some minimum percentage on a daily basis? Please explain why twice per year application of chemical dust suppressant to active haul roads outside of the pit influence boundary is adequate. Assuming there is an air quality benefit to the use of graders, the draft SIP needs to specify the required frequency of grading.

Response to H-220: These comments are addressed in the 1994 PM_{10} SIP, the $PM_{2.5}$ SIP, and the current Approval Order.

H-221 [KUC]: As part of its effort to develop the PM2.5 SIP, UDAQ completed an analysis of Reasonably Available Control Technology (RACT) for major sources located in the Salt Lake City nonattainment area. Specifically, this analysis showed that current operating practices at the Bingham Canyon Mine (BCM) represent RACT; in other words, UDAQ's RACT determination found that there were no additional controls that were currently available that KUC could implement to reduce emissions from the BCM. Yet, in the draft Part H Emission Limits, the agency proposed measures that would require KUC to reduce the Mine's annual emissions by 10% by 2019.

KUC understands the difficulties created by our airshed and recognizes that to attain the PM2.5 NAAQS, UDAQ will need to impose requirements that result in reduced emissions from an array of sources. For point source, those emission reductions are necessarily tied to the control technology identified in the associated PACT determination as reflected in the Technical. Support Document (TSD). For the BCM, the TSD concludes that there are no additional controls available beyond those already in use at the Mine.

Notwithstanding the conclusion that there are no further measures reasonably available to reduce emissions at BCM, UDAQ's Part H emission limits require an additional 10% reduction for BCM.

KUC will, of course, work toward finding a method of meeting the requirements that UDAQ has proposed for BCM. However, if approved, UDAQ's Part H emission limits will put KUC in the difficult, if not impossible, position of being required to cut emissions absent curtailing operations.

Response to H-221: UDAQ thanks the commenter for the comment. Final RACT determinations were made at the December 4, 2013 meeting of the Utah Air Quality Board when it voted to accept SIP Subsection IX.A.21: Control Measures for Area and Point Sources, Fine Particulate Matter, PM2.5 SIP for the Salt Lake, UT Nonattainment Area. UDAQ anticipates the need to submit a new BACT/RACT analysis as part of a Subpart 4 Serious PM2.5 Nonattainment Area SIP in the near future, and would invite the commenter to resubmit this comment at that time.

H-222 [KUC]: As explained in Comment #1, UDAQ has proposed a 10% reduction in emissions at the Bingham Canyon Mine. These reductions are presumed necessary to demonstrate modeled attainment of the 24-hour PM2.5 standard in 2019. However, and as explained in greater detail in KUC's comments submitted on the attainment demonstration, and incorporated herein by this reference, it is very unlikely that reductions from BCM will aid in attaining the NAAQS. Accordingly, KUC requests that UDAQ provide a quantitative modeling assessment evaluating whether the proposed 10% reduction in BCM emissions will materially aid in achieving attainment. We understand that even if certain control measures are deemed to constitute RACT, they may be eliminated if they will not advance the attainment demonstration by a calendar year.

Response to H-222: See response to H -221 regarding RACT

H-223 [WRA]: At the Bingham mine, Emission Limits impose a rolling 12-month combined limit for NOX, PM2.5 and SO2 of 6,205 tons until January 1, 2019, then a decreased limit of 5,585 tons after that time. Emission limitations must be set for each pollutant separately in order to be enforceable. Moreover, to protect the 24-hour PM2.5 NAAQS, these limits must be expressed, at a minimum, as a 24-hour standard. In addition, separate, enforceable limits must be set for key pollutants at all major process points or operations. Moreover, any emission limitations must be monitored, recorded and enforceable and the Emission Limits fail to specify how these mandatory requirements will be met.

Response to H-223: The BCM operates 8760 hours per year and there is very little change in operations on a day to day basis. The mileage limit, which is a daily limit, protects the 24 hour standard. Therefore, this limit on the combined PM2.5, NOx and SO2 per 12-month rolling protects the NAAQS. Provisions for enforcement are found in the PM10 SIP, the PM2.5 SIP, and the permit.

H-224 [WRA]: Comment: The proposed provisions do not include any limit on amount of material movement (ore plus waste) per 12-month period. As a result, the emission limits on the mine are not federally enforceable and therefore do not qualify as RACT. The January 2011 NOI for the mine expansion includes a BACT analysis. The control technologies included as BACT in this permit must be included in the Emission Limits. BACT for the in-pit crusher and conveyor system was identified as fabric filters with grain loading of 0.007 gr/dscf for the new in-pit crusher. And enclosures for the conveyor system were identified as BACT.

Response to H-224: A limit on the material movement is an indirect limit on the emissions. The limits on the rolling 12-month totals for $PM_{2.5}$, SO_2 and NO_x is a direct limit on the emissions and is a more efficient means to control the impact on the NAAQS. The permit serves as an enforcement mechanism for protection of the 24-hour PM2.5 standard.

H-225 [WRA]: Comment: The proposed control on miles traveled contains no monitoring and record keeping requirement and there is no explanation as to how this restriction translates into emission reductions. The measures designed to control fugitive dust on roads are likewise not enforceable or monitored and include vague, unenforceable statements such as "as conditions warrant." Therefore, the controls on the mine do not represent RACT.

Response to H-225: These comments are addressed in the 1994 PM_{10} SIP, the $PM_{2.5}$ SIP, and the current Approval Order. These documents contain recordkeeping requirements and enforceable conditions.

H-226 [WRA]: Finally, RACT evaluation for the mine states that the company should "replace all trucks that are older than 14 years with trucks that have the highest tier rating available and that in the future as trucks are replaced, the replacements use the highest tier engine available." This should be included in the Emission Limits.

Response to H-226: The reduction in emissions for the truck upgrades are included in the combined PM2.5, NOx and SO2 per 12-month period limit of 5,585 tons. Emission factors for these higher tiered engines are regulated by Title II of the Clean Air Act.

H-227 [HEAL]: Part H of the proposed PM2.5 SIP includes a rolling 12-month emission limit for NOX, PM2.5 and SO2 combined of 6,205 tons until January 1, 2019, then a decreased limit of 5,585 tons after that time. Emission limits need to be set for each pollutant separately in order to be enforceable. EPA commented on the draft PM2.5 SIP that a specific limit should be set for SO2 and VOC. In addition, separate emission limits need to set for NOX and PM2.5. And separate, enforceable limits must be set for key pollutants at all major process points or operations. 2008 actual emissions for NOX, PM2.5, SO2 and VOC equal 6,032.55 tons while 2019 projections for all four pollutants total 5100.14 tons (the totaling of emissions here does not represent any agreement with UDAQ's combined emission limit). These projected reductions will be beneficial to overall PM2.5 levels in the Salt Lake area and the associated control strategies should be reflected in the PM2.5 SIP so that proper credit can be taken towards attaining the PM2.5 NAAQS.

Response to H-227: The emissions from the mine are related to each other. When one goes up the others will also go up. Setting a limit on the combined emissions serves the same purpose as individual limits. Control of these combined emissions limits the overall effect on the ambient air. The control strategy is to limit the emissions that effect the PM2.5 attainment demonstration.

H-228 [HEAL]: EPA comments on the draft PM2.5 SIP explain that there should be a limit set for the amount of material movement (ore plus waste). In 2011, Utah issued a new Approval Order for the Bingham Canyon Mine Expansion and submitted a PM10 SIP revision to EPA for this action. The expansion includes an increased limit on the amount of material moved during a 12-month period from 197,000,000 tons to 260,000,000 tons ore and rock. This expansion should be factored into the PM2.5 SIP and the increased limit on the amount of material moved should be included as a control measure in the SIP. The January 2011 NOI for the mine expansion includes a BACT analysis. The control technologies included as BACT in this permit must be included in the SIP as well. BACT in the NOI for the in-pit crusher and conveyor system was identified as fabric filters with grain loading of 0.007 gr/dscf for the new in-pit crusher. And enclosures for the conveyor system were identified as BACT.

Response to H-228: These comments are addressed in the 1994 PM_{10} SIP, the $PM_{2.5}$ SIP, and the current Approval Order. These documents contain recordkeeping requirements and enforceable conditions.

H-229 [HEAL]: Because fugitive dust is a major source of emissions from the mining operations, including haul roads, the PM2.5 SIP must include effective dust control measures that include detailed mitigation and monitoring measures that will minimize exposure to particulates. Part H of the SIP includes some dust suppression measures for KUC, Bingham Canyon Mine and EPA commented on these provisions in the draft SIP, stating that, these measures are not enforceable, as there are no recordkeeping provisions to ensure the measures are implemented. Further, since these measures are much less detailed and comprehensive than what was in the original PM10 SIP that EPA approved in 1994, these measures are less stringent than what Kennecott has been required to use since before 2008.

The proposed measures therefore do not appear to represent a reduction from 2008 baseline emissions. Please explain why the more detailed dust control measures are planned to be dropped.

Response to H-229: DAQ would point to its federally approved NSR permitting program and its role as a required element (from 172(c)(5)) of these plan provisions. The approval orders issued as a consequence of this program offer a repository for the many emission limitations that would not rise to the level of importance compelled by the SIP. The DAQ also has a minor source permitting program, and a BACT analysis is required for minor sources and for major sources that are below significance. Collectively, these limits and the NSR rules and regulations that prescribe them, are part of a control strategy that is adequate for timely attainment of the PM2.5 NAAQS.

H-230 [HEAL]: According to the proposed PM2.5 SIP, PM2.5 emissions from KUC Mine and Copperton Concentrator are expected to decrease from 737.65 tpy in 2008 to 427.67 tpy projected in 2019. But it is not reasonable to rely on PM2.5 emissions decreases in the SIP's attainment demonstration unless the decrease is due to an enforceable control strategy under the SIP.

Response to H-230: See previous response regarding control and enforcement mechanisms (H-228).

H-231 [HEAL]: Part H of the SIP includes a requirement for KUC to limit the daily total mileage of haul trucks to 30,000 miles. EPA commented on this same provision in the draft SIP, stating: "…no explanation has been provided on how this restriction translates into NOx emissions and whether it represents a reduction from 2008 baseline emissions. Also, it is not enforceable, as there are no enforceability provisions for this restriction. It is unclear whether the daily total mileage limit is a new control strategy for the proposed SIP and whether any credit is taken for the reductions. This limit must be included in the PM2.5 SIP as an enforceable control measure.

Response to H-231: See previous response regarding control and enforcement mechanisms (H-228).

H-232 [Heal]: The "Point Source Reduction Summary" table in Part H of the proposed SIP lists reductions of 64.7 tons per year NO2 from higher tier emissions beginning in 2019. Thus, it appears that the attainment demonstration is taking credit for this control; however, the proposed rules in Part H do not reflect this requirement. UDAQ's RACT evaluation for the source states, "The RACT recommendation is that KUC replace all trucks that are older than 14 years with trucks that have the highest tier rating available and that in the future as trucks are replaced, the replacements use the highest tier engine available." This should be included in the proposed SIP.

Response to H-232: The control is reflected in the combined NOx, SO2, PM2.5 limit. The decrease in emissions from 6,205 tons to 5,585 tons will be achieved through the replacement of truck engines with higher tiered engines.

KENNECOTT – POWER PLANT, TAILINGS IMPOUNDMENT, BONNEVILLE BORROW PLANT AND LABORATORY

H-233 [EPA]: Page 4 of the RACT Evaluation Report says a RACT analysis was not performed on existing main boilers 1, 2 and 3 at the Power Plant, because they are being replaced by a Unit 5 combustion turbine and will not be in operation after 2016. However, draft SIP subsection IX.H.12.m. says that boilers 1, 2 and 3 shall not be operated after January 1, 2018, or upon commencing operation of Unit 5, whichever is sooner. This implies that boilers 1, 2 and 3 are allowed to operate until possibly 2018. Draft SIP subsection IX.H.12.m. does not specify any emission limits for boilers 1, 2 and 3. Please explain why emission limits for boilers 1, 2 and 3 are not proposed to be retained until 2018 as RACT. As we explained in the General Comments above, for an approvable attainment demonstration, the state needs to identify the existing local measures in the area that contribute to attainment of the NAAQS in that area, so that EPA can approve those measures specifically as RACT.

Response to H-233: The existing boilers (Units 1, 2 and 3) are already listed in the 1994 EPA approved PM10 SIP in Section [~~IX.H.2.b.Z~~]IX.A.2.2.Z. This section of the SIP is being retained and will not be superseded by the issuance of any of SIP Sections IX.H.11, 12 or 13. Repeating previously listed limitations would be redundant.

H-234 [EPA]: Draft SIP subsection IX.H.12.m. says the NOx and VOC emission limits for Unit #5 at the Power Plant (combined cycle combustion turbine) apply "under steady state operation." No limits are listed for any other periods of operation. As we have noted in our comments above on SIP subsection IX.H.11.d, this is inconsistent with CAA requirements that SIP emission limits apply at all times, including periods of startup, shutdown, and malfunction (SSM). We have similar concerns regarding the language that appears twice that reads, "The limited use of natural gas during startup, for maintenance firings and break-in firing does not constitute steady-state operation and does not require stack testing."

Response to H-234: See response to H-5 regarding the inclusion of SSM Provisions.

H-235 [EPA]: Draft SIP subsection IX.H.12.m. does not indicate any stack test methods or other means (e.g., CEMS) for demonstrating compliance with any of the proposed emission limits at the Power Plant, nor are any averaging times indicated for the emission limits. Draft SIP subsection IX.H.11.e. should be cross-referenced for stack test methods, as was done for other sources (e.g., Central Valley Water Reclamation; Chemical Lime), and averaging times indicated for the emission limits. For CEMSs, appropriate requirements should be specified. In particular, we do not understand why NOx CEMS is not required. Please explain.

Response to H-235: SIP Section IX.H.11.e is automatically cross-referenced for all sources in subsections H.12 and H.13 based on the language of IX.H.11. Additional cross-referencing is not required.

H-236 [EPA]: Stack testing for Unit #5 (combustion turbine) is proposed to be required once every three years. We are concerned with stack test frequencies longer than one year. Please explain why this test frequency is sufficient to ensure continuous compliance with the limits.

Response to H-236: The Unit #5 combustion turbine is a natural gas-fired turbine that has a well-established and well-understood emission rate that does not vary over the short-term. Stack-testing on this unit is established primarily to address long-term maintenance issues and to demonstrate that the unit's overall performance has not degraded with extended use. A once-every-three-year stack test is sufficient for this demonstration.

H-237 [EPA]: Page 7 of the RACT Evaluation Report identifies NOx RACT for boiler 4 as installation of LNB with OFA and SCR. The RACT Summary Table indicates that these controls will be installed by 2019, with an expected NOx reduction of 170 tpy. Please explain why an earlier date would not be achievable. Please also explain why draft SIP subsection IX.H.12.m. does not include a requirement to install these controls. The subsection does indicate that the NOx emission limit for boiler 4 changes from 336 ppmdv to 60 ppmdv on January 1, 2018, but it is not clear that this can be treated as an enforceable requirement to install new controls.

Response to H-237: These items represent large capital investments with significant lead times, engineering, construction, startup, shakedown and testing involved. This date was reached through negotiation with the source based on the source's expected construction schedule after consideration of each factor.

Unit 4 would have to install the mentioned control in order to meet the 60 ppmdv limit. In order to install the listed controls and meet this required NOx reduction, Unit #4 will need to be taken offline. As Unit #4 will continue to operate during the period of construction of Unit #5 – which requires demolition of Units #1, #2 and #3 – the earliest compliance date for the necessary upgrades at Unit #4 was January 1, 2018.

H-238 [EPA]: Draft SIP subsection IX.H.12.m.i.D proposes to restrict fuel to natural gas during winter months (November through February) for boiler #4, with coal allowed the rest of the year. EPA is evaluating whether proposals to apply requirements on a seasonal basis are an acceptable approach to address PM2.5 under the CAA. Also, during the winter months, the draft SIP proposes to allow Unit #4 to burn coal during natural gas curtailments, plus sufficient time to empty the coal bins following the curtailment. Was any coal usage modeled in the attainment demonstration? If not, then we would be concerned with allowing the burning of coal until the coal bins are empty.

Response to H-238: Coal was not modeled because KUC would only be using coal on a contingency basis.

H-239 [EPA]: The RACT Evaluation Report identifies this source as consisting of not only the Power Plant, but also the Tailings Impoundment, Bonneville Borrow Plant (BBP) and Laboratory. For the Tailings Impoundment, page 9 of the Report identifies RACT as water spray/wet suppression, polymer application, and revegetation. These are all existing practices. Draft SIP subsection IX.H.12.m., however, contains no requirements for dust control at the Tailings Impoundment. As we explained in the General Comments above, for an approvable attainment demonstration, the state needs to identify the existing local measures in the area that contribute to attainment of the NAAQS in that area, so that EPA can approve those measures specifically as RACT. For the BBP, page 9 of the RACT Evaluation Report says RACT has not yet been identified because the BBP has not yet started operation. However, draft SIP subsection IX.H.12.m. proposes as RACT a limit of 12,500 miles per day of haul truck use. Please explain how this was determined to be RACT. Also, the draft SIP needs to specify a means to determine compliance with the mileage limit.

Response to H-239: The Tailings Impoundment has 7.10 TPY of $PM_{2.5}$ emissions. Based on this amount it is a minor source to the $PM_{2.5}$ nonattainment. The Bingham Canyon Mine has a similar mileage limit that was approved in the 1994 PM_{10} SIP.

H-240 [EPA]: Please explain how the emissions used for NAAQS attainment modeling compare to the emissions that are proposed to be allowed, on a plantwide daily basis. The table provided to us on October 31, 2013 indicates that projected actuals were used for modeling. We do not know if the projected actuals take into account the expected shutdown of boilers 1, 2 and 3, and replacement with a combustion turbine. There is also no information on what the allowable emissions will be, on a plantwide daily basis, after RACT is applied. Our objective here is to see if there is a substantial difference between the proposed allowable emissions and the emissions used for modeling.

DAQ Response: The projected PTEs were modeled at 90% of the PTE.

H-241 [WRA]: In violation of the Clean Air Act, there is no analysis and no proposed provisions for the Tailings Impoundment facility. The Director must consider RACT for the tailings pile. At a minimum, the fugitive dust control provisions in the current Title V operating permit should be incorporated into the SIP. Moreover, there is no RACT for the proposed Borrow Area Plant, which must be, at a minimum, aggregated with the Tailings Impoundment facility. The proposed controls on the former plant are not enforceable and include no monitoring or recordkeeping requirements and there is no indication how this control will result in any emissions calculation relied on for the purposes of the SIP.

Response to H-241: The RACT analysis is only conducted on major sources. The tailings impoundment is a minor source and so a RACT analysis was not conducted.

H-242 [WRA]: Kennecott Lab and Power Plant: The PM2.5 SIP should include emission limits for the power plant and lab. The Title V operating permit dust control measures for the tailings impoundment that are incorporated by reference in the PM10 SIP should also be included in the PM2.5 SIP.

Response to H-242: Emission limits are included in the $PM_{2.5}$ SIP for the power plant. The lab was not included because it is a minor source with emissions less than 1 TPY. Regarding the tailings impoundment, the PM10 SIP remains enforceable.

H-243 [WRA]: Under the NSR permit and the PM10 SIP, boilers 1-3 have PM10 and NOX emission limits; these limits should also be included in the PM2.5 SIP. The PM2.5 SIP should include limits on the amount of fuel used at all Kennecott boilers as such controls are plainly RACT. The RACT analysis concluded that the paving of haul roads as a dust control measure was technically infeasible. However, the Morenci Mine permit includes temporary paving as one option for dust control. This measure should be reevaluated as RACT.

Response to H-243: See response to H-233 regarding retention of PM10 SIP Section [~~IX.H.2.b.Z~~]IX.A.2.2.Z.

H-244 [WRA]: There is no basis in the record to support the decision that Kennecott may continue to operate boilers 1-3 until 2018. An early retirement date is warranted and should be implemented as expeditiously as possible. Stack testing every three years at Unit 5 is not RACT. Testing should be required at least every year. The record does not support the decision to allow Kennecott to operate Unit 4 using coal at any point in the winter months. In any case, without a limit on the number of days that Kennecott may use coal as a fuel during the winter, the Director cannot claim that he will attain the NAAQS unless his model includes unlimited wintertime use of coal. With regard to stack sampling, Stack testing frequency is based on engineering judgment and the permit writer's knowledge regarding the specific sources process and history. How close a source is to a threshold (significance, PSD, etc.), what existing stack requirements are in place, and whether the equipment is controlled with industry wide accepted technology are some things considered when setting testing frequency.

Response to H-244: See responses H-238 regarding the use of coal during natural gas curtailment periods, and regarding implementation of RACT controls on Units #4 and #5.

H-245 [HEAL]: The PM2.5 SIP should include emission limits for the power plant, lab and tailings impoundment. EPA commented on the draft PM2.5 SIP that the Title V operating permit dust control measures for the tailings impoundment that are incorporated by reference in the PM10 SIP, should also be included in the PM2.5 SIP. This is of critical importance, especially due to the fact that PM2.5 emissions are expected to increase 126.21 tpy according to the year 2019 projections in the proposed SIP. The source of the PM2.5 increases could be due to the planned construction of the Bonneville Power Plant, which is expected to contribute mostly fugitive emissions. There are no controls for this source included in Part H of the proposed SIP; the SIP should include controls for this source.

Response to H-245: Emission limits for the power plant are listed in the PM2.5 SIP. The tailings and lab are minor sources and were not included in the PM2.5 SIP.

H-246 [HEAL]: Under the NSR permit and the PM10 SIP, boilers #1-3 have PM10 and NOX emission limits; these limits should also be included in the PM2.5 SIP in order to ensure they continue to help the nonattainment area achieve the PM2.5 NAAQS in case either the PM10 SIP or the permit are revised in the future. All boilers at the Morenci Mine in Arizona have permit limits on the amount of fuel used. The PM2.5 SIP should include limits on the amount of fuel used at all KUC boilers.

Response to H-246: See response to H-233 regarding retention of PM10 SIP Section [~~IX.H.2.b.Z~~]IX.A.2.2.Z.

H-247 [HEAL]: The RACT analysis concluded that the paving of haul roads as a dust control measure was technically infeasible. However, the Morenci Mine permit includes temporary paving as one option for dust control. This measure should be reevaluated during the BACT process for KUC.

Response to H-247: With respect to comments on RACT, UDAQ thanks the commenter for the comment. While final RACT determinations were made at the December 4, 2013 meeting of the Utah Air Quality Board when it voted to accept SIP Subsection IX.A.21: Control Measures for Area and Point Sources, Fine Particulate Matter, PM2.5 SIP for the Salt Lake, UT Nonattainment Area. UDAQ anticipates the need to submit a new BACT/RACT analysis as part of a Subpart 4 Serious PM2.5

Nonattainment Area SIP in the near future, and would invite the commenter to resubmit this comment at that time.

KENNECOTT – SMELTER, REFINERY AND MOLYBDENUM AUTOCLAVE PROCESSING PLANT

H-248 [EPA]: Please explain how the emissions used for NAAQS attainment modeling compare to the emissions that are proposed to be allowed, on a plantwide daily basis. The table provided to us on October 31, 2013 indicates that projected actuals were used for modeling. The RACT Evaluation Report does not indicate what the actual emissions are on a plantwide daily basis. There is also no information on what the allowable emissions will be, on a plantwide daily basis, after RACT is applied. Our objective here is to see if there is a substantial difference between the proposed allowable emissions and the emissions used for modeling.

Response to H-248: This is a general comment on modeling that will be addressed under the general comments.

H-249 [EPA]: Draft SIP subsection IX.H.12.n. proposes emission limits in pounds per hour for the Main Smelter Stack and for the Refinery boilers and Combined Heat Plant. The RACT Evaluation Report does not give any indication what emission limits in lb/hr might represent RACT. Please explain how the proposed emission limits in lb/hr were calculated and determined to represent RACT.

Response to H-249: These limits were determined in the BACT analysis and represent RACT and BACT. Please refer to the RACT Evaluation Report.

H-250 [EPA]: Draft SIP subsection IX.H.12.n. does not specify any stack test methods. Draft SIP subsection IX.H.11.e. should be cross-referenced for stack test methods, as was done for other sources (e.g., Central Valley Water Reclamation; Chemical Lime), and an averaging time specified for the NOx emission limits at the Refinery.

Response to H-250: Section H.11.e requires the sources to use the stack testing methods listed.

H-251 [EPA]: Draft SIP subsection IX.H.12.n.i.A.I.3. proposes a NOx emission limit for the Main Stack on an annual average. Please explain how an annual average can represent RACT in a plan that is intended to attain a 24-hour NAAQS.

Response to H-251: The hourly limit was modeled. This demonstrates compliance.

H-252 [EPA]: Draft SIP subsection IX.H.12.n.i.A.III.l. proposes NOx RACT allowable emission limits for the Holman Boiler on a 30-day average. Please explain how 30-day averages can represent RACT in a plan that is intended to attain a 24-hour NAAQS.

DAQ Response: The emissions from the hourly limit was modeled. This demonstrates compliance.

H-253 [EPA]: Draft SIP subsection IX.H.12.n.i.B.III, on monitoring of NOx emissions at the Holman Boiler, requires "CEMS or alternate method determined according to applicable NSPS standards." Why is the language about an alternate method necessary? Hasn't the monitoring method already been established? Why would it change?

Response to H-253: The limit states “CEM or alternate method determined according to applicable NSPS standards”. An NSPS standard may require an alternated method.

H-254 [EPA]: For the Tankhouse Boilers, draft SIP subsection IX.H.l2.n.ii.B. states, "compliance with the emission limitation by the second boiler shall be determined by the stack test of the first boiler." We question whether that's acceptable, regardless of whether the two boilers are identical in make, model, and pollution control equipment. What about the proper operation and maintenance of the boilers and control equipment? Also, stack testing for the Tankhouse Boilers at the Refinery is proposed to be required once every three years. We are concerned with stack test frequencies longer than one year. Please explain why this test frequency is sufficient to ensure continuous compliance with the limits.

Response to H-254: Stack testing frequency is based on engineering judgment and the permit writer’s knowledge regarding the specific sources process and history. How close a source is to a threshold (significance, PSD, etc.), what existing stack requirements are in place, and whether the equipment is controlled with industry wide accepted technology are some things considered when setting testing frequency. If the analysis by the engineer revealed a need for annual sampling it would have been required.

H-255 [EPA]: Draft SIP subsection IX.H.12.n.ii.C. allows for use of #2 fuel oil during testing and maintenance periods at the Tankhouse Boilers. No limit is placed on the duration of these periods. If the emissions associated with such fuel use have not been modeled in the attainment demonstration, then we would be concerned with such use.

Response to H-255: Natural gas is a cheaper fuel and any source would not operate them longer than needed. Therefore, a limit on the hours of operation for maintenance is not required.

H-256 [EPA]: Draft SIP subsection IX.H.12.n.iii. needs to define the terms "MAP" and "TEG."

Response to H-256: MAP is defined in the RACT Evaluation Report as Molybdenum Autoclave Processing and TEG is a common term used for turbines and stands for Turbine Exhaust Gas.

H-257 [WRA]: The emission limitation on the Holman Boiler must be, at a minimum, averaged over 24-hours in order to ensure compliance with the NAAQS. Similarly, the NOX emission limit at the Main Stack is improperly averaged over a year and therefore is not sufficient to protect the PM2.5 NAAQS. Except for the Main Stack, Emission Limits does not include PM2.5 emission limits for the smelter and refinery; limits should be included in order to ensure this source does not increase its adverse impacts on the PM2.5 nonattainment area. The PM2.5 emissions from the Main Stack should be subject to continuous monitoring. Emission Limits does not include the requisite recordkeeping, calculation procedures, and CEMS QA for the CEMS. EPA considers such provisions to be necessary for the smelter main stack emission limits for SO2 and NOX to be enforceable. Also, no test method is specified for PM2.5, and there are no recordkeeping or reporting requirements for any pollutants at either the smelter or the refinery.

Response to H-257: The Homan boiler is monitored by a CEM and this verifies compliance. RACT determined that the $PM_{2.5}$ limit was sufficient. The hourly limit for the main stack was modeled. This demonstrates compliance. Section H.11.e requires the sources to use the listed stack testing methods.

H-258 [WRA]: The proposed SO2 emission limits for acid plant tailgas, which are 1,050 ppmdv on a 3-hour rolling average and 650 ppmdv on a 6-hour rolling average, are the same as in the 2005 PM10 SIP submittal, but that submittal was out-of-date with respect to NSR permit limits in effect at that time. The emission limits for acid plant tailgas in the August 2000 AO, which have been carried over into all subsequent permits, are 250 ppmdv on a 6-hour block average, 170 ppmdv on a 24-hour calendar day average, and 100 ppmdv on an annual average. These latter emission limits must be incorporated into the SIP as RACT.

Response to H-258: DAQ would point to its federally approved NSR permitting program and its role as a required element (from 172(c)(5)) of these plan provisions. Collectively, these permit limits and the NSR rules and regulations that prescribe them, are part of a control strategy that is adequate for timely attainment of the PM2.5 NAAQS.

H-259 [WRA]: Kennecott is constructing a Molybdenum Autoclave Processing Plant that will begin operating in 2014. Projected emissions in the 2019 inventory for the Kennecott Smelter and Refinery show increases of 158.36 tpy NOX, 188.22 tpy PM2.5, 581.78 tpy SOX and 18.93 tpy VOC. Plainly, additional RACT must be considered to decrease emission from the facility. After all, as indicated above, more stringent RACT that takes into consideration the benefits of emissions reductions and the severity of Salt Lake’s pollution problem warrant controls sufficient to ensure that emissions from Kennecott do not increase. This is particularly warranted where the Director cannot show attainment until December 2019. In any case, the Autoclave plant will begin operation in 2014. Any limits and controls under the permit must be included in the PM2.5 SIP.

Response to H-259: Final RACT determinations were made at the December 4, 2013 meeting of the Utah Air Quality Board when it voted to accept SIP Subsection IX.A.21: Control Measures for Area and Point Sources, Fine Particulate Matter, PM2.5 SIP for the Salt Lake, UT Nonattainment Area. UDAQ anticipates the need to submit a new BACT/RACT analysis as part of a Subpart 4 Serious PM2.5 Nonattainment Area SIP in the near future, and would invite the commenter to resubmit this comment at that time.

H-260 [WRA]: PM2.5 emission limits of 85 lb/hr (filterable) and 434 lb/hr (filterable and condensable) are proposed for the smelter main stack, apparently to replace the PM10 limits currently in effect. After taking into account the ratio of PM2.5 to PM10, the proposed limit for filterable PM2.5 appears to be no more stringent than the limit for filterable PM10 in the 2005 PM10 SIP submittal, which was 89.5 lb/hr. Therefore, the proposed limit represents little, if any, reduction from 2008 baseline emissions and therefore is out of date and not RACT.

Response to H-260: With respect to comments on RACT, UDAQ thanks the commenter for the comment. While final RACT determinations were made at the December 4, 2013 meeting of the Utah Air Quality Board when it voted to accept SIP Subsection IX.A.21: Control Measures for Area and Point Sources, Fine Particulate Matter, PM2.5 SIP for the Salt Lake, UT Nonattainment Area and SIP Subsection IX.A.22: Control Measures for Area and Point Sources, Fine Particulate Matter, PM2.5 SIP for the Provo, UT Nonattainment Area, UDAQ anticipates the need to submit a new BACT/RACT analysis as part of a Subpart 4 Serious PM2.5 Nonattainment Area SIP in the near future, and would invite the commenter to resubmit this comment at that time.

H-261 [WRA]: The proposed emission limit at the refinery of 9.5 lbs/hr for the combined NOX emissions of two boilers is equivalent to the limit in the 2005 PM10 SIP submittal, which was 0.057 tons per day for each boiler. The proposed limit therefore does not appear to represent RACT. Moreover, any emission limits on the refinery should be subject to continuous monitoring. Overall, the proposed provisions for the Kennecott smelter and refinery do not appear to represent any reduction from 2008 baseline emissions for any pollutant and do not represent RACT.

Response to H-261: With respect to comments on RACT, UDAQ thanks the commenter for the comment. While final RACT determinations were made at the December 4, 2013 meeting of the Utah Air Quality Board when it voted to accept SIP Subsection IX.A.21: Control Measures for Area and Point Sources, Fine Particulate Matter, PM2.5 SIP for the Salt Lake, UT Nonattainment Area and SIP Subsection IX.A.22: Control Measures for Area and Point Sources, Fine Particulate Matter, PM2.5 SIP for the Provo, UT Nonattainment Area, UDAQ anticipates the need to submit a new BACT/RACT analysis as part of a Subpart 4 Serious PM2.5 Nonattainment Area SIP in the near future, and would invite the commenter to resubmit this comment at that time.
HEAL Comment

H-262 [WRA]: The proposed PM2.5 SIP does not include emission limits for the smelter and refinery; limits should be included in order to ensure this source does not increase its adverse impacts on the PM2.5 nonattainment area.

Response to H-262: The $PM_{2.5}$ SIP has emission limits for the Main Stack, Acid Plant Tail Gas and Holman Boiler at the smelter, and the two Tankhouse Boilers and the Combined Heat Plant at the refinery.

H-263 [WRA]: Kennecott is constructing a Molybdenum Autoclave Processing Plant that will begin operating in 2014. Projected emissions in the 2019 inventory for the Kennecott Smelter and Refinery show increases of 158.36 tpy NOX, 188.22 tpy PM2.5, 581.78 tpy SOX and 18.93 tpy VOC. The new plant will begin operation in 2014. Any limits and controls under the permit must be included in the PM2.5 SIP.

Response to H-263: The emission limits for the Combined Heat Plant are included in the $PM_{2.5}$ SIP.

UNIVERSITY OF UTAH

H-264 [EPA]: The table provided to us on October 31, 2013 indicates that the emissions used for NAAQS attainment modeling were projected actual emissions. It is not clear what this means, considering that the following changes at the University have occurred, or will occur, after the 2008 emission baseline year, as outlined in the RACT Evaluation Report:

Lower campus heating plant (Building 303):
• New natural-gas-fired turbine cogeneration unit (73 MMBtu/hr) has been installed and is operating
• Boiler 5 (105 MMBtu/hr) was shut down by 2012 and is being replaced by two 40 MMBtu!hr boilers, expected to be operational by 2017; net expected Ox reduction is 13.15 tpy.
• Boiler 4 (105 MMBtu/hr) will be decommissioned by 2016 and replaced by two 40 MMBtu/hr boilers, expected to be operational by 20 19; net expected NOx reduction is 13 .15 tpy.
• Boiler 3 (105 MMBtu/hr) will be decommissioned by 2018 and replaced by two 40 MMBtu!hr boilers, expected to be operational by 2021 ; net expected NOx reduction is 13.15 tpy.
Upper campus heating plant (Building 302):
• Boiler 4 (87.5 MMBtu/hr) received an upgraded burner management system in 2012; estimated NOx reduction was 6.04 tpy.
• Boilers 1 and 3 (87.5 MMBtu/hr each) will each receive an upgraded burner management system by 2016; expected NOx reduction is 6.04 tpy at each boiler. Please explain whether the projected actual emissions take all this into account and how the projected actual emissions were calculated, on a daily basis. Please also explain what the allowed emissions are for the same time period, on a daily basis. Our objective here is to see if there is a substantial difference between the proposed allowable emissions and the emissions used for modeling.

Response to H-264: The projected actual emissions referenced above take into account the upgrades that will be completed at the U of U by 2019.

H-265 [EPA]: The only proposed RACT emission limits in draft SIP subsection IX.H.l2.t. are for the lower campus heating plant:
• 9 ppmdv for the 40 MMBtu/hr boilers that will replace boilers 4 and 5
• 9 ppmdv for the cogen turbine when it is operating alone, or 15 ppmdv when it is operating with the WHRU duct burner
• 187 ppmdv for boiler 3 (because it will not be replaced until 2021)

There are no proposed RACT emission limits or emission control requirements for the boilers at the upper campus heating plant, even though the RACT Evaluation Report identifies RACT for NOx at the upper campus boilers to be an upgraded burner management system ("02 trim technology"). The RACT Summary Table identifies 0 2 trim technology as RACT for NOx at the upper campus heating plant and indicates that the upper campus plant is being credited with 12.07 tpy of NOx reduction as a result. If the University is being credited with an emission reduction due to new controls, then this needs to be reflected as proposed RACT in the SIP, with a requirement to install such a system by a specific deadline. As stated in our General Comment #3, if RACT consists of existing controls, the state needs to identify the existing local measures in the area that contribute to attainment of the NAAQS in that area, so that EPA can approve those measures specifically as RACT.

Response to H-265: The controls identified are due to recent permit modifications. See previous response regarding the various enforcement mechanisms (H-228).

H-266 [EPA]: The RACT Summary Table indicates that one (or more) boilers at the lower campus heating plant will be replaced for PM, S02, NOx and VOC control by 2017. The Table also indicates that 0.2 trim technology will be installed for NOx control at the upper campus heating plant units 1 & 3 by 2015. Please explain why earlier dates would not be achievable. Similarly, the draft SIP specifies dates in 2017, 2018 and 2019 for initial stack tests for various boilers and for Boiler #3 to convert to backup/peaking status. Please explain why earlier dates would not be achievable.

Response to H-266: The U of U is doing several upgrades and they cannot all be done at the same time. The upgrades have to be performed over a longer time frame due to budgeting for the upgrades and the complete system cannot be out of service. The university needs to retain the ability to obtain heat and steam from some boilers while upgrades are being completed at others. This required staggering of upgrades results in the SIP compliance dates listed in IX.H.12.t.

H-267 [EPA]: No NOx test method is specified in draft SIP subsection IX.H.12.t. Draft SIP subsection IX.H.11.e. should be cross-referenced for stack test methods, as was done for other sources (e.g., Central Valley Water Reclamation; Chemical Lime).

Response to H-267: The test methods have been addressed in Section IX.H.11.e, and automatic cross-referencing is accomplished by the language of IX.H.11.

H-268 [EPA]: Stack testing is proposed to be required once every three years at the boilers for NOx. We are concerned with stack test frequencies longer than one year. Please explain why this test frequency is sufficient to ensure continuous compliance with the limits.

Response to H-268: These boilers are natural gas fired and have very little variation in their performances. Therefore, every three years is sufficient enough to verify compliance with the limits.

BRIGHAM YOUNG UNIVERSITY – MAIN CAMPUS

H-269 [EPA]: The current NSR permit (Approval Order) dated June 19, 2012, specifies NOx emission limits of 95 ppmdv at Boiler #1 and 127 ppmdv at Boilers #4 and #6. The RACT Evaluation Report explains that Boiler #1 is utilized as a standby heat source and was not included in the RACT analysis. Boilers #2, #3 and #5 are coal-fired but are prohibited from burning coal in winter months, therefore were also not included in the RACT analysis. We think all of these units should be assessed for RACT. For example, if Boilers #2, #3 and #5 are capable of burning natural gas, the RACT analysis should address potential control technologies and limits for that fuel.

Response to H-269: Boilers #2, #3 and #5 are coal-fired and are not capable of burning natural gas. They are prevented from burning coal in the winter inversion period. This is why a RACT analysis was not performed on them, and why they are not included in SIP Section IX.H.13.a.

H-270 [EPA]: Draft SIP subsection IX.H.13.a. proposes a NOx RACT limit of 30 ppmdv for Boilers #1, #4 and #6, with compliance testing required at #4 and #6 by January 1, 2017. We assume this means that LNB + FGR is expected to be able to achieve 30 ppmdv. Boiler #1 is only required to be retrofitted with LNB + FGR, and then tested, if it operates more than 300 hours per rolling 12-month period. All six boilers are restricted to natural gas as fuel from November 1 to February 28. No emission limits are specified prior to January 1, 2017. Assuming that EPA concludes that seasonal controls are creditable in the attainment demonstration, and that the proposed limits and deadlines are consistent with CAA requirements, the SIP must nonetheless include the existing emission limits (cited above) for Boilers #1, #4 and #6, and indicate that these limits remain in effect until the new limits take effect on January 1, 2017. The SIP must also specify provisions sufficient to determine compliance with the limits.

Response to H-270: The EPA approved 1994 PM_{10} SIP has limits for BYU and these limits remain in effect until they're replaced by an updated standard.

H-271 [EPA]: As mentioned above, draft SIP subsection IX.H.13.a. says Boiler #1 may be operated for up to 300 hours per rolling 12-month period without triggering the need to comply with the 30 ppm emission limit that represents RACT (i.e., LNB + FGR). What is the impact if those 300 hours occur during a PM2.s episode? How did the state model Boiler #1? Again, we caution that EPA is still evaluating whether seasonal controls are an acceptable approach to address PM2.s under the CAA; in other words, EPA must determine whether a seasonal restriction on coal burning, or seasonal limits, are creditable in the state's attainment demonstration.

Response to H-271: Boiler #1 is smaller than either of boilers #4 or #6 and the emissions would be less than those emitted from these boilers. A reduction in emissions from this boiler was not modeled because the higher emission rate of the other two boilers was modeled instead as a worse-case estimate.

H-272 [EPA]: Pages 2 and 5 of the Report identify NOx RACT for Boilers #4 and #6 as replacement of the burner spud tips and adding 18% FGR (Flue Gas Recirculation). The RACT Summary Table refers to this as LNB + FGR and indicates this is expected to yield 11.1 tpy of NOx reduction. The RACT Summary Table indicates that LNB and FGR will be installed at Boilers #4 and #6 by 2017. Please explain why an earlier date would not be achievable.

Response to H-272: BYU is in the process of evaluating whether to upgrade the boilers or replace the entire heating plant. Replacement would result in even a greater reduction in emissions for the boilers. An earlier installation date would prevent this alternate option from occurring. See previous comment regarding individual control strategies.

H-273 [EPA]: Regarding Boilers #2, #3 and #5: Assuming that EPA concludes that seasonal controls are creditable in the attainment demonstration, and that the existing limits for these units are consistent with CAA requirements for RACT/RACM, the NOx emission limits for these boilers (331 ppmdv, listed in the current NSR permit) should be included as part of RACT in draft SIP subsection IX.H.13.a., along with provisions sufficient to determine compliance with the limits. It is not clear whether these units are capable of burning natural gas. This is relevant to the RACT analysis and should be explained.

Response to H-273: These units are not capable of burning natural gas and are prevented from operating in the EPA approved 1994 PM_{10} SIP during the wintertime.

H-274 [EPA]: Please explain how the emissions used for NAAQS attainment modeling compare to the emissions that are proposed to be allowed, on a plantwide daily basis. The table provided to us on October 31, 2013 indicates that projected actual emissions were used as the basis for modeled emissions. The RACT Evaluation Report provides some information on 2008 baseline actual emissions for portions of the plant, but we are unable to determine what the emissions were on a daily basis in winter months, for the boilers that have operated in winter. Also, we are unable to determine from draft SIP subsection IX.H.13 .a. how much emissions are proposed to be allowed on a daily basis during those months. Our objective here is to see if there is a substantial difference between the proposed allowable emissions and the emissions used for modeling.

Response to H-274: The emissions allowed and modeled are as if they operated during the winter months.

H-275 [EPA]: No NOx test method is specified in draft SIP subsection IX.H.13 .a. Draft SIP subsection IX.H.11.e. should be cross-referenced for stack test methods, as was done for other sources (e.g., Central Valley Water Reclamation; Chemical Lime).

Response to H-275: The test methods are listed in Section IX.H.11.e and automatic cross-referencing is accomplished by the language of IX.H.11.

H-276 [EPA]: Two items should be clarified for the benefit of all readers: First, the SIP should specifically identify the number of central heating plant units and their names, instead of merely referencing " [a]ll central heating plant units." Second, the testing requirements for Unit #1 are not clear. We suggest rephrasing the relevant part of the footnote to read," ... then, within 18 months of exceeding 300 hours of operation, low NOx burners with Flue Gas Recirculation shall be installed and an initial stack test shall be performed to determine compliance with the emission limit in H.13.a.ii .A above. A stack test shall be required every three years thereafter."

Response to H-276: With respect to request #1, the units in question are already listed in SIP Section IX.H.13.a.ii. With respect to request #2, UDAQ has received additional comments which further adjust the language of this footnote. See response to BYU Unit #1 operation and testing requirements below.

H-277 [EPA]: Stack testing is proposed to be required at Units #4 and #6 once every three years. We are concerned with stack test frequencies longer than one year at these Units. Please explain why this test frequency is sufficient to ensure continuous compliance with the limits.

Response to H-277: These are natural gas-fired boilers and have little or no variability in their operation. Therefore, a stack test every three years is sufficient to verify compliance.

H-278 [BYU]: BYU submitted comments to clarify the limits in Section IX Part H.13.

Response to H-278: The requested changes by BYU are acceptable and will be implemented as shown below. The revised emission limits accurately reflect the results of the RACT analysis.

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. The sulfur content of the fuel oil shall not exceed 0.0015 % by weight.

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

SOURCE	POLLUTANT	lb/hr	ppmdv (3% 0_2 dry)
A. Unit #1	NOx	5.44	36 ppm
B. Unit #4	NOx	7.68	36 ppm
C. Unit #6	NOx	7.68	36 ppm

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

SOURCE	POLLUTANT	INITIAL TEST	TEST FREQUENCY
A. Unit #1	NOx	*	every three years
B. Unit #4	NOx	January 1, 2017	every three years
C. Unit #6	NOx	January 1, 2017	every three years

* 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 the Low NO_x burners with Flue Gas Recirculation shall be installed and tested. Unit #1 shall be stack tested within 18 months of exceeding 100 hours of operation.

HILL AIR FORCE BASE

H-279 [EPA]: Page 1 of the RACT Evaluation Report says Hill AFB is subject to existing requirements in 40 CFR 60, subparts De, IIII and JJJJ, as well as requirements in 40 CFR 63, subparts N, GG, ZZZZ, and DDDDD. These bodies of regulation contain numerous requirements for the pollutants of interest for the PM2.5 SIP. Compliance with NSPS (40 CFR 60) and MACT (40 CFR 63) requirements is identified in several places in the RACT Evaluation Report as RACT for NOx and VOCs. Hill AFB is also subject to numerous other requirements for the pollutants of interest for the PM2.5 SIP (primarily for VOCs). These requirements may be found in the title V permit and pertain to topics such as surface coating operations, degreasing, and solvents. However, the only requirement proposed as RACT in draft SIP subsection IX.H.12.j. is a limit of 0.5 tpd of VOC emissions from painting and depainting operations. No such limit is proposed in the RACT Evaluation Report. As we explained in the General Comments above, for an approvable attainment demonstration, the state needs to identify the existing local measures in the area that contribute to attainment of the NAAQS in that area, so that EPA can approve those measures specifically as RACT.

Response to H-279: See previous responses regarding the duplication of existing federal requirements and individual emission controls (H-52, 53). See also previous responses regarding RACT final determination (H-35).

H-280 [EPA]: The only proposed emission limit in draft SIP subsection IX.H.12.j is 0.5 tpd for VOC emissions from painting and depainting operations. Subparagraph ii says, "Compliance with this daily average shall be determined monthly." This language is not approvable because it is inadequate to ensure enforceability of the limit. The SIP needs to specify the method(s) used to determine compliance, identify what specific painting and depainting operations at Hill AFB are to be covered by this limit, and require recordkeeping. Also, the import of Subparagraph ii is not clear. Is this intended to make the daily limit into a monthly average? If so, we question whether an averaging time longer than 24 hours can represent RACT in a plan that is intended to attain a 24-hour NAAQS.2)

Response to H-280: Hill is unable to track the VOC emissions from painting and depainting operations on a daily basis. The main base has too many painting and depainting operations occurring (+100) on the base on a daily basis to track. Hill has requested to track the quantity of paint and depainting material being issued on a location/operation basis as the material is issued. Hill's painting and depainting operations order paint and depainting material from one centralized controlled location on the base where it is stockpiled for use. Hill is unable to track when the material is used on a daily basis at each ancillary location, but can track the total amount being issued and average that amount over the next time each location/operation orders more material. Occasionally, some painting/depainting operations on base may not use all of the issued material prior to its expiration date – in which case the unused material is tracked and then deducted from the daily average being determined monthly.

DAQ believes the daily limit which is averaged monthly is an acceptable limit for a source of this size and complexity. DAQ agrees that Hill attempting to track paint and depainting operations and material located over 100 locations on a daily basis and calculating the VOC emissions associated with material in a 24 hour period is overly burdensome and unreasonable.

H-281 [EPA]: We could find no explanation how 0.5 tpd of VOC emissions from painting and depainting operations represents RACT. The RACT Evaluation Report does not propose any such limit. Please explain how this proposed limit was calculated to be RACT.

Response to H-281: The 0.5 tons per day of VOC emissions from painting and depainting operations limit is based upon the 2008 emissions inventory as a direct representation of projected actual emissions. There was a small growth factor included (0.01 tpd) in this amount to reflect the fact that past inventory data were actual emissions in a down-turned economy (2008).

H-282 [EPA]: Page 3 of the RACT Evaluation Report says no additional control is considered RACT for NOx for the 12 boilers at Hill AFB, on the basis of high cost, in dollars per ton of NOx removed. The main reason given is that normally steam is provided from outside (Wasatch Energy Systems) and the boilers are only kept for the event that steam no longer can be provided from the outside. This may be appropriate for emergency operation, but if the outside source of steam is lost permanently, then the boilers at Hill AFB will have to operate routinely from then on. This could allow the dollars-per-ton costs to become feasible. Please address this concern.

Response to H-282: The concept of outside source steam lost would require Hill to operate the boilers for steam demand. Hill is limited by a fuel consumption limit in the Consolidated Boilers Approval Order and the boilers extended use would trigger a permit modification, which in turn would require this outdated equipment to be updated to current BACT standards.

H-283 [EPA]: The RACT analysis for degreasing operations (section 2.1.d of the RACT Evaluation Report) appears inadequate. Questions include: Are there older units that could be replaced with newer units with up-to-date passive and active emissions control methods, such as condensers or carbon adsorption systems? Is there a smaller number of larger units that can be addressed separately, and/or multiple units in concentrated areas that could be addressed in groups? Has the use of low VOC solvents been examined? The July 16, 2013 TechLaw RACT evaluation states: "Nellis Air Force Base is in the RBLC as permitted with vapor condensers and recovery for controlling VOC emissions. It appears that there could be potential for emissions reductions from the same or similar technologies for some but not all of the degreasing operations at HAFB." Please explain whether these options have been considered, or will be considered.

H-283 [EPA]: RACT was conducted on the degreasing operation and the source category was reviewed and it was determined that Hill was not addressing the reclaimed solvents and not addressing unit emissions control efficiencies. After addressing the reductions to the source category the emissions were reduced to 5.6 tons per year for multiple units.

H-284 [EPA]: We have the same comment on the RACT analysis for general solvent use (section 2.1.g of the RACT Evaluation Report) as for degreasing operations above. Other facilities should be examined for potential RACT control measures.

Response to H-284: RACT was conducted on the General Solvent Use Operation. As the source category was reviewed, it was determined that Hill is limited by military specifications on solvents. Each operation is limited to no organic hazardous air pollutant (HAP) emissions from chemical stripping formulations and agents or chemical paint softeners, except as allowed in 40 CFR 63.746(b)(2). Also, in accordance with 40 CFR 63.746 (b)(3), Hill cannot use more than 50 gallons per year of organic HAP-containing chemical strippers or alternatively 365 pounds of organic HAP per depainted military aircraft for spot stripping and decal removal. Waste solvent reclamation uses condensers by design and no other controls have been identified in the RBLC.

GENEVA NITROGEN

H-285 [EPA]: Page 2 of the RACT Evaluation Report states, "The Prill Tower is a low density prill production unit with no emission control equipment. The uncontrolled prill tower is the major source of ammonium nitrate (NH4N03) particulate matter." Page 3 rejects a wet scrubber as not economically feasible for PM10/$PM_{2.5}$ control. Page 5 says RACT is represented by the following: "The Prill Tower shall continue to use pollution prevention measures of reducing microprill formation and reduce carryover of fines through entrainment." No such measures are proposed as RACT in draft SIP subsection IX.H.13. b. Page 28 of Geneva Nitrogen's own RACT analysis describes some pollution prevention measures that have already been accomplished during 1995 through 2012. Please explain whether the intent is to require Geneva Nitrogen to continue to look for additional pollution control measures, and if so, why this is not included as a requirement in draft SIP subsection IX.H.13.b.

Response to H-285: The RACT evaluation performed for the Prill Tower resulted in an unreasonable cost associated with the installation of particulate control ($250,000 per ton of $PM_{2.5}$ removed). Therefore, the UDAQ ruled out this technology as a control option. The pollution prevention measures which are currently in practice at Geneva Nitrogen have been accounted for in DAQE-AN0825005-03. See previous responses relating to individual emission controls, and the use of the RACT Evaluation Reports. Therefore the requirement to look for additional pollution control measures is unnecessary and cannot be written as an enforceable limitation in SIP subsection IX.H.13.b., as it is unknown if and when additional pollution control measures may become available.

H-286 [EPA]: Please explain how the emissions used for NAAQS attainment modeling compare to the emissions that are proposed to be allowed, on a plant wide daily basis. The table provided to us on October 31, 2013 lists emission figures in tons/year that were used for modeling. The basis for these figures (e.g., projected actuals, proposed allowables, 90% of PTE, or possibly something else) is not indicated. Also, please provide information on what the proposed allowables equate to, in terms of plant wide emissions. Our objective here is to see if there is a substantial difference between the proposed allowable emissions and the emissions used for modeling.

Response to H-286: The 2008 actual emissions provided in the Utah County $PM_{2.5}$ SIP demonstration were as follows:

2008

PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	NH_3
38.92	18.71	0.01	111.93	0.09	1.33	2.70

NAAQS attainment modeling provided for the following years 2014, 2017, and 2019 were all based upon projected actuals with the appropriate growth factor (as explained in the modeling section, under "Use of Growth Factors") included. The modeled emissions included were as follows:

2014

PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	NH_3
47.36	22.77	0.01	136.20	0.11	1.62	3.28

2017

PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	NH_3

53.96	25.94	0.01	155.19	0.12	1.85	3.74

2019

PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	NH_3
58.59	28.17	0.02	168.49	0.13	2.00	4.06

H-287 [EPA]: Please explain why condensable PM is not accounted for in the RACT Evaluation Report, nor in the proposed PM10 emission limit in draft SIP subsection IX.H.13.b. (which is 0.22 tpd at the Prill Tower). The draft SIP subsection does not indicate whether stack testing needs to include condensable PM. Please also explain why PM10 is specified rather than $PM_{2.5}$.

Response to H-287: UDAQ will require a condensable PM_{10} emission limitation as well as an acceptable $PM_{2.5}$ emission limitation, appropriate stack testing method(s) and periodic testing requirements at a later date. This information is currently unavailable. The UDAQ will require a future NSR permit modification for these emission limitation modifications. Therefore, due to no available information, neither a PM_{10} nor $PM_{2.5}$ condensable emission limitation and associated stack testing and testing method(s) are not included in the $PM_{2.5}$ SIP.

H-288 [EPA]: No stack test methods are specified in draft SIP subsection IX.H.13.b. Draft SIP subsection IX.H.11.e. should be cross-referenced for stack test methods, as was done for other sources (e.g., Central Valley Water Reclamation; Chemical Lime).

Response to H-288: See previous responses to H-275 regarding SIP Section IX.H.11.e..

H-289 [EPA]: There appear to be conflicting provisions for stack testing. Testing is specified in draft SIP subsection IX.H.l3.b.ii.A, in 13.b.v., and in 13.b.v.A.I. Subsection 13.b.ii.A says that emissions shall be tested every three years but does not indicate testing for which limit or when testing shall commence. Subsection 13.b.v. says compliance testing is required on the Prill Tower, Montecatini Plant, and Weatherly Plant, but says that testing shall be performed no later than January 1, 2019. Again, this subsection does not specify testing for which limits, and it is not clear how this dovetails with subsection 13.b.ii.A. Furthermore, we do not understand why it is appropriate to defer testing until January 1, 2019. Subsection 13.b.v.A.I. indicates that stack testing for the NOx limits must occur every three years, but does not specify a date for the initial test. The SIP must clearly state a reasonable date by which stack testing must start, the frequency of testing after that, and the limits for which the testing is required.

Response to H-288: Geneva Nitrogen is an existing source, and currently operates under NSR permit DAQE-AN0825005-03. This permit requires stack testing limitations for NO_x for the Montecatini acid plant (32.4 lb/hr and 267 ppmdv) and Weatherly acid plant (19.4 lb/hr and 438 ppmdv). The stack testing has been performed every two (2) years for the Montecatini plant and every three (3) years for the weatherly plant. Geneva Nitrogen is current and up to date on the stack testing requirements of the NSR permit and will continue to do so. The RACT analysis resulted in Geneva Nitrogen volunteering to reduce the emission rates by the year 2019 to 30.8 lb/hr and 288 ppmdv for the Montecatini acid plant and 18.4 lb/hr and 350 ppmdv for the Weatherly acid plant. As no individual control options were specified to reach these limits, UDAQ agreed through negotiation with the source to accept the lower limits in exchange for coordinated stack testing (which is allowed under the provisions of R307-165 which specifies a minimum frequency of once every 5 years). As Geneva Nitrogen has consistently shown emissions in compliance with its current limits, a stack test frequency of every three years for all three emission units is sufficient. The requirements of IX.H.13.b.v.A.I are intended to apply to all NOx testing requirements. The paragraph located above is in error and will be removed.

H-289 [EPA]: Draft SIP subsection IX.H.13.b.v.B appears to be a requirement derived from the Compliance Assurance Monitoring rule. The language raises several questions. First, since it requires use of a NO_x CEMS, why should it not be used for determining emission compliance, rather than just a compliance "indicator"? Second, there's a lack of clarity- for which NO_x emission limit(s) is this supposed to be used? Third, it says excursions trigger an inspection, corrective action, and a reporting requirement. Inspection by whom? Corrective action by whom? What sort of report and to whom? This subsection should be clarified.

Response to H-289: The NO_x CEMS is utilized for both the Montecatini and Weatherly acid plants as a monitor of performance of those units, and not as a direct measure of emissions. UDAQ agrees with the commenter that this language is confusing and adds no value to the SIP in terms of emission reduction or NAAQS attainment demonstration. UDAQ anticipates the need to submit an additional analysis as part of a Subpart 4 Serious PM2.5 Nonattainment Area SIP in the near future, and removal of this condition should be addressed at that time.

H-290 [WRA]: Geneva Nitrogen: The proposed emission limitations for this facility do not control for PM2.5. RACT for PM2.5 is required. According to the Emission Limits, "compliance testing is required on the Prill tower, Montecatini Plant, and Weatherly Plants. The test shall be performed as soon as possible and in no case later than January 1, 2019." Yet, there is nothing in the record to support this significant delay in implementing this SIP provision. A stack test every three years is not RACT.

Response to H-290: UDAQ recognizes that Geneva Nitrogen currently operates under NSR permit DAQE-AN0825005-03. This permit requires stack testing limitations for NO_x for the Montecatini acid plant (32.4 lb/hr and 267 ppmdv) and Weatherly acid plant (19.4 lb/hr and 438 ppmdv). The stack testing has been performed every two (2) years for the Montecatini plant and every three (3) years for the weatherly plant. Geneva Nitrogen is current and up to date on the stack testing requirements of the NSR permit and will continue to do so. The RACT analysis resulted in Geneva Nitrogen volunteering to reduce the emission rates by the year 2019 to 30.8 lb/hr and 288 ppmdv for the Montecatini acid plant and 18.4 lb/hr and 350 ppmdv for the Weatherly acid plant. Because there was not a specific control option which could be considered RACT for these plants the UDAQ accepted the voluntary reduction of these emission rates by Geneva Nitrogen. UDAQ also agreed to a coordinated stack testing frequency for Geneva Nitrogen, which is established as once every three years.

PROCTER & GAMBLE PAPER PRODUCTS COMPANY

H-291 [EPA]: Page 9 of the RACT Evaluation Report identifies low-NOx burners and good combustion practices as RACT for the paper machine dryer burners. Draft SIP subsection IX.H.12.s., however, does not propose any NOx emission limits as RACT for the paper machine dryer burners. The current NSR permit (Approval Order), dated August 2, 2013, includes NOx emission limits for the paper machine process stacks of 0.09 lb/MMBtu and 13.50 lb/hr. Please explain why the NOx limits in the current NSR permit are not included as RACT emission limits.

DAQ Response: See previous responses relating to individual emission controls, and the use of the permit and the PM2.5 SIP as control mechanisms (H-228).

H-292 [EPA]: Draft SIP subsection IX.H.12.s. indicates that a PM2.5 RACT emission limit is "to be determined" for the Paper Machine Process Stacks, following stack testing that is proposed to be required by January 1, 2015, to "establish the ratio of condensable PM2.5." The SIP subsection indicates that a $PM_{2.5}$ limit will then be established in the Approval Order. This is not approvable. RACT needs to be included in the SIP (including condensable PM2.s), not determined at a future date or specified in an AO.

Response to H-292: Proctor & Gamble Paper Products has not tested the paper machine process stack for PM2.5. It was unknown what percentage of the PM10 emissions from the Paper Machine Process Stack was PM2.5. The PM2.5 has been conservatively estimated at 100% PM10 to PM2.5 until actual data can be established through testing The testing cycle was originally set at once every five years and it was originated on the initial start-up of the operation. The testing of the Paper Machine Process Stack consists of testing the Paper Processing stack, Combustion Dryer stack, Wet Exhaust stack, Dry End stack and the Under Dryer Stack and adding the results of the tests. These stacks are spread out along the Paper Machine process line and not collected in any common dust or stack. When the second line is installed and operating an initial test will be conducted to determine the PM2.5 emissions. If the second line is not installed prior to the five year testing frequency on the first line, the testing results from the first line will be used to set limits in both the AO and PM2.5 SIP.

H-293 [EPA]: Page 3 of the revised TechLaw RACT Evaluation Report indicates that there are three diesel tanks at Proctor & Gamble which emit a total of over 150 tpy of VOCs. TechLaw recommends a RACT evaluation for these tanks. Please explain why the state 's own RACT Evaluation Report does not include any such evaluation.

Response to H-293: The three diesel storage tanks in the revised TechLaw RACT Evaluation Report were misallocated emissions from the Converting Room operations. Once Proctor & Gamble Paper Products was questioned on the 150 tons per year of VOC's from the three diesel storage tanks, Proctor & Gamble Paper Products resubmitted their 2008 emissions inventory and identified the 150 tons per year of VOC emissions as originating from Converting Room operations. This documentation is listed in TechLaw's RACT Evaluation Report section 6.0 "Evaluation of Additional Information Provided by Proctor and Gamble in Response to RER Recommendations" first paragraph.

H-294 [EPA]: Stack testing is proposed to be required once every five years. We are concerned with stack test frequencies longer than one year. Please explain why this test frequency is sufficient to ensure continuous compliance with the limits.

Response to H-294: The testing cycle was originally set by the Approval Order once every five years and was originated on the initial start-up of the operation. The testing of the Paper Machine Process Stack consists of testing the Paper Processing stack, Combustion Dryer stack, Wet Exhaust stack, Dry End stack and the Under Dryer Stack and adding the results of the tests. These stacks are spread out along the Paper Machine process line and not collected in any common dust or stack. Testing on an annual basis would require the source to tests five stacks per process line and with two process lines the source would have to preform 10 stack tests annually. The source is able to electronically monitor the process equipment for optimally operation of the process line for efficiency and quality control of product.

H-295 [WRA]: The proposed provisions do not include, in its entirety the NOX emission limits in the current AO at the four boilers (3.3 lb/hr and 45 ppm for each boiler) and at the two paper machines (13.50 lb/hr and 0.09 lb/MMBtu for each machine). These are the main emitting units at the facility. The proposed provisions include a heading for PM2.5, but no emission limit for of PM2.5, just a placeholder saying "To be determined by January 1, 2015." This is not sufficient, particularly given there is no evidence in the record to suggest why such a limit cannot be established in early 2014. No VOC emission limits, or surrogates for VOC limits, are proposed. The VOC emission potential was listed in the initial NSR permit action as 213 tons per year. A RACT review for VOC is warranted. The proposed provisions do not specify any stack test methods, nor any recordkeeping or reporting requirements. A stack test every five years is not RACT. "

Response to H-295: DAQ would point to its federally approved NSR permitting program and its role as a required element (from 172(c)(5)) of these plan provisions. The approval orders issued as a consequence of this program offer a repository for the many emission limitations that would not rise to the level of importance compelled by the SIP. The DAQ also has a minor source permitting program, and a BACT analysis is required for minor sources and for major sources that are below significance. Collectively, these limits and the NSR rules and regulations that prescribe them, are part of a control strategy that is adequate for timely attainment of the PM2.5 NAAQS.

MODELING TSD COMMENTS FROM EPA

MTSD – 1

We recommend including in the modeling TSD a summary of the post-SMOKE modeled emissions for each year. This is a useful quality assurance product and is helpful in comparing and verifying that the emissions input to CMAQ are consistent with the raw emissions data that was input to the SMOKE emissions processing system. For example, plots of daily total emissions for each major emissions sources category and selected species could be included in the TSD.

Response to MTSD - 1

A chart or table that compares SMOKE input to SMOKE output for major source categories is useful for quality assurance. One possible way to demonstrate this is to compare emissions data prior to controls before and post-SMOKE for future years. Using this comparison with information found in tables 2 and 3 (TSD section 4d), for example, could also provide a more complete picture of our overall SIP strategies' efficacy. In the future, this analysis will be placed into the SMOKE discussion in the TSD (section 4c).

MTSD - 2

Emission factors for wood smoke have been updated for the 2010 baseline inventory. The organic carbon fractions shown in figures 5.11, 5.12, and 5.13 of the Provo and Salt Lake SIP appear to have not been updated to account for the changes to the wood smoke emission factors.

Response to MTSD - 2

EPA is correct in that 5.11, 5.12, and 5.13 have not been updated to reflect the changes to the organic carbon fraction due to updated wood smoke emission factors. DAQ will provide updated figures in an updated version of the modeling TSD. The CMAQ model performance of organic carbon with and without the new wood smoke emission factors can be found in the CMAQ modeling TSD (http://www.airquality.utah.gov/Pollutants/ParticulateMatter/PM25/SaltLakeProvo/docs/tsd/chapter4/4_c_CMAQ_SLC_ProvoSIPs_09_17_2013.pdf) in Figures D.4 (Hawthorne), D.9 (Lindon), and D.4 (Bountiful). These time series figures show the improvement the new wood smoke emission factors have on the performance of modeled organic carbon.

MTSD - 3

The speciation category “other” is not addressed in the discussion of performance of model PM2.5 speciation performance. Depending on the model performance for the components of “other” and the components represented by the “other” category, it could provide an unexplored opportunity for additional control strategies.

Response to MTSD - 3

UDAQ will provide a breakdown of the composition of the “other” category for both the filter speciation data and the model output in an updated version of the modeling TSD. The analysis of the “other” category will be examined to see if it may lend an opportunity for additional control strategies.

MTSD - 4

The composition of the “other” PM2.5 speciation component should be evaluated more closely. A breakdown of the composition of the “other” category should be provided for both filter speciation data and model output. Also, a description of the mass reconstruction calculation used in the modeling should be provided.

Response to MTSD - 4

We will provide a breakdown of the composition of the “other” category for both the filter speciation data and the model output in an updated version of the modeling TSD. Also, a description of the mass reconstruction technique used will be provided.

MTSD - 5

To assess whether the "other" in Lindon's pie graph was dominated by crustal, the EPA extracted elemental speciation data for several likely "other" components for winter days above 25ug/m3 for 2008-2013 at Lindon, Hawthorne and Bountiful. Peak elemental mass fractions were for chlorine, potassium and iron, rather than silicon which is usually expected to be the largest contributor by mass for crustal samples. This was true for all three speciation samplers. Potassium was the third largest contributing element by mass fraction, although potassium is often not included in the calculation of filter mass reconstruction algorithms. It is not known whether UDAQ used potassium in the reconstruction algorithm used to derive Figures 5.11-13. Derivation information is requested to complete our review.

Response to MTSD - 5

The Utah DAQ and a research team from the University of Utah looked into the source of the particulate chloride during the wintertime inversion pollution episodes. Our attempts to narrow down the source of chloride did not yield any conclusive results.

MTSD - 6

Speciation data from 2009 and 2010 episodes was used in generating Figures 5.11-13; Figure 5.11 for Hawthorne shows good agreement for "other" between the monitor and model. The figure above shows very marked differences, year to year, in chlorine contribution to PM2.5’s mass on high PM2.5 days. In most mass reconstruction algorithms, chlorine is assumed to be contained in sea salt particles; since ions in sea water are 55% chlorine by mass, chlorine mass is converted to sea salt mass by multiplying by 1.8 (1 /55%). Chlorine also composes approximately 55% of the ion mass in the Great Salt Lake, so if the chlorine in the Wasatch Front speciated PM2.5 is assumed to be in salt particles derived from evaporation of Great Salt Lake droplets, multiplication by 1.8 would also be appropriate. This would imply that in 2013, with chlorine content on high PM2.5 days at Hawthorne reaching 4.18%, assumed sea/lake salt particle mass reached 7.5% of total PM2.s mass. This variation year-to-year in a single component of "other" might suggest that the agreement between the model and monitored data in 2009 and 2010 at Hawthorne but not at Bountiful or Lindon may be more random chance than an indication that the model is replicating the actual filter chemistry for the speciation components of "other". A trend analysis of SIN "other" at the speciation sites within the weight of evidence section might be valuable…

Response to MTSD - 6

Multiplying the chlorine mass by 1.8 would be helpful to reconstruct the sea-salt-like composition of the chloride (sodium chloride). However, mass balance analysis did not provide enough sodium, or other counter-ions expected to be found in marine environments, to account for the presence of the chloride in the PM. Additionally, the Great Salt Lake has very little wave action in wintertime to warrant an adequate direct sodium chloride contribution.

MTSD - 7

While most mass reconstruction algorithms assume chlorine will be in the form of sea salt on speciation filters, most speciation ... at Hawthorne do not seem to support this assumption. ... Examination of chlorine to sodium ratios on high PM2.5 speciation sampling days in 2008-2012 shows chlorine to sodium ratios generally range from 12 to 100 or more, suggesting a robust secondary chlorine aerosol chemistry is present. This would make the assumptions of sea salt composition inappropriate for mass reconstruction, and also point to a secondary aerosol pathway not currently captured in modeling. Weight of evidence evaluation of chlorine speciation data would be helpful in understanding model shortcomings and mismatches (if any) between speciation reconstruction assumptions and modeled "other”.

Response to MTSD - 7

We are considering a number of other pathways that may be introducing chloride into the ambient PM. One of them is the secondary formation of ammonium chloride via the nitryl chloride ($ClNO_2$) mechanism. Further studies are needed to more accurately quantify the contribution of the secondary chloride formation process.

MTSD – 8

It would be helpful in assessing issues like that above, and projected model and SIP performance, if the CMAQ TSD included breakdowns of speciated relative response factor (RRF) by location for each of the future projections (2014, 2017, and 2019). This would show which portions of the PM2.5 aerosol are moving toward attainment under the SIP controls expeditiously, and which are decreasing more slowly (or growing) under the SIP control measures.

Response to MTSD - 8

Table 6 and an additional paragraph have now been added to the TSD (section 4d) that shows PM2.5 species’ RRF’s for 2014, 2017 and 2019 at our Hawthorne and Lindon monitors. These RRF’s correspond to the 5-year FDV’s reported in our SIP. This should be effective in highlighting the strengths/weaknesses of our SIP strategies.

MTSD – 9:
For the SIP narrative Table 3.2, the 3-year design values are shown in whole numbers, rounded in accordance with 40 CFR Part 50, Appendix N rounding rules, but the baseline design values shown cannot be derived by averaging the design values shown. Instead, Region 8's understanding of the MATS calculation is that the baseline design values shown are derived by averaging 3-year averages of 98th percentile values, truncating to the right of the 0.1 ug/m3 decimal place, averaging the truncated three 3-year averages in a 5-year design value period, then again truncating to the right of the 0.1 ug/m3 decimal place. A note to this effect, or showing the decimal values in the table would make the table more understandable

DAQ Response:

We will consult 40 CFR Part 50, Appendix N and consider changing the numerical precision or formatting of Table 3.2 values in the future. It should be noted that the future design-values reported in the SIP narrative are, themselves, derived directly from baseline design-values generated by MATS. In other words, 3-year averages are not manually entered for our attainment testing.

MTSD - 10
MATS TSD, 4.d-3 . "Spatial interpolation options, "blank mass" amount and boundaries used OC mass estimation are left set at MATS default values (please see MATS documentation)." Presumably this should have read "and boundaries used for the OC mass estimation"? The reference to the MATS documentation with a citation, such as Sec. 7 .1.2.2, p. 172 for the OC mass estimation defaults, would help our review and the public's review.

Response to MTSD – 10
The presumption stated in the comment is correct. The relevant sentence has now been corrected to read:

> "Spatial interpolation options, "blank mass" amount and parameters used for OC mass estimation are left set at MATS default values."

For additional guidance, the following sentence has been added immediately after the preceding sentence:

> "Please refer to the MATS user's manual, sections 7.5.2 and 7.5.3, for clarification on these particular settings."

MTSD - 11
It is not clear whether the data shown in Figure 1.1 is exceedance days for all of the Salt Lake nonattainment area. For example, in 2000, the chart shows about 14 exceedance days, while the Air Quality System (AQS) database shows 22 separate exceedance days just considering the monitors in Salt Lake County. Given that, the conclusion "The number of PM2.5 exceedances between 1999 and 2012 has decreased by approximately 31% in the Salt Lake non-attainment area" is not well supported. Is this based on a rolling average over some period of time, the slope of the linear regression, or some other method? The conclusion should be qualified, given that the number of monitors operating and their sampling frequencies have changed over time. This is particularly pronounced in Logan, where in 2002 the monitor recorded 11 exceedances between January 8 and February 22 on a one day in 3 schedule, before moving to a daily schedule May 14 of that year; therefore measured exceedances in 2000-2002 in Logan could be approximately 113 of the number of days which actually had PM2.5 above the NAAQS. This makes the

quoted decrease statistics in numbers of exceedance days unreliable, or difficult to interpret accurately. There needs to be further discussion on the derivation of the data presented, since there is such a large discrepancy between what is stated in the SIP and what is in AQS.

Response to MTSD - 11

Exceedance Days Count. The exceedance counts presented in the document were the aggregated by dates and their appropriate CSA. Thus, if the network showed four exceedances for a particular statistical area on a certain day that even counted as a single exceedance for the CSA for that date. Thus, double or triple counting of the NAAQS exceedances was avoided.

Furthermore, the exceedance data was gathered only between December and February to ensure that the summertime wind events and fireworks are eliminated are not included in the analysis. The exception to this was Cache County, where the month of March was added to include some of the seldom yet significant PM events due to inversions.

Exceedance Days Count in Cache. The point about 1-in-3 day monitoring is valid. However, there is not accurate way to estimate the actual number of exceedance days in that area prior to the commencement of daily monitoring. The current numbers prior to May of 2002 should be regarded as the minimum number of exceedances.

Generally, the exceedance trends were constructed to estimate the overall trend and variability (specifically the impact of meteorology) of the PM exceedances over the last 15 years.

MTSD - 12

Section 1.1 cited trends in exceedance days based on 1999-2012 data (2001-2012 for Logan), 1.2 shows data through the first half of 2013. Section 1.1 did not include this 2013 exceedance day data, but, if included, only Salt Lake City would then have a downward trend in exceedance days since the start of monitoring; the long term trend for Utah County is essentially flat, while the long term trend for Logan (without correcting for the monitoring frequency change in 2002) is upward.

Response o MTSD - 12

The data included in section 1.1 related only the Salt Lake, Cache, and Provo/Orem CSA's. The change in trend was calculated by the value of the change in linear regression associated the annual graph for each respective area. The rolling average was not used for the analysis because of the arbitrariness in selection of the averaging period. For consistency between each CSA, only calendar year data for winter month was used.

Furthermore, the change in trend with the addition of 2013 data further drives the effect that meteorological conditions have on year-to-year and the overall pollution trends in the state. Both 2004 and 2013 years have been exceptional with respect to the number of recorded exceedances and significantly affect the linear regression analysis.

Adding the incomplete 2013 data changes the long term trend of the regression, but only because of the exceptional number of the exceedance days due to the very persistent and prolonged inversion episodes observed that year. Including either of the years (2004 or 2013) at the edges of the data introduces a significant distortion to the overall long-term trend. We are confident that the overall trend of the annual exceedance days is negative, however, the year-to-year values may vary significantly due to the variability of the meteorological conditions.

MTSD - 13
EPA states that it is a matter of opinion that 2012's snow depth and surface temperatures were not as extreme as 2013's snow depth and surface temperatures. EPA also states that technical support could be quantified so that the selection of the baseline period looks less arbitrary.

Response to MTSD - 13
We will do a more comprehensive analysis of yearly temperature and snow depth means and how they compare and deviate from the long term average. The point of this analysis will provide information on which years may be considered outliers when compared to the long term average. This analysis will included in a future updated Weight of Evidence (WOE) TSD.

Note that the current analysis contains a portion of 2013 data. For regulatory purposes, an entire calendar year must be completed to be included in the calculation of a baseline design value period. Therefore, at the time of submittal of the 24 Hour PM2.5 SIP, calendar year 2013 couldn't be officially used in the calculation.

MTSD - 14
The Salt Lake City morning weather balloon launch is between 4 AM or 5 AM instead of between 5 AM or 6 AM.

Response to MTSD - 14
Agreed. This will be noted in the updated WOE TSD.

MTSD - 15
EPA states that in the calculation of inversion strength as a temperature difference from Celsius to Fahrenheit is simply multiplication by 9/5 and not the formula 9/5 +32.

Response to MTSD - 15
UDAQ agrees that the conversion from Celsius to Fahrenheit in terms of a temperature difference is simply multiplication by 9/5 and changes will be made to the updated WOE TSD.

MTSD - 16
The assessment of inversion strength in 2012 vs. 2013 is somewhat qualitative and is a matter of opinion; that data should be assessed quantitatively. Looking at the entire 1999-2013 data set, rather than just 2008-2013 would allow a more objective analysis.

Response to MTSD - 16
We will do a more quantitative analysis of yearly inversion strength. The inversion strength analysis will be updated to include the entire 1999-2013 data set. This analysis will be included in a future updated WOE TSD.

Note that the current analysis contains a portion of 2013 data. For regulatory purposes, an entire calendar year must be completed to be included in the calculation of a baseline design value period. Therefore, at the time of submittal of the 24-hour $PM_{2.5}$ SIP, calendar year 2013 couldn't be officially used in the calculation.

MTSD - 17

Some quantitative comparison of the years 2012 and 2013 with the long term means would validate the statement that year 2013 exhibited extreme inversion periods, while 2012's inversions were more typical in strength.

Response to MTSD - 17

We will do a more quantitative analysis of the 2012 and 2013 inversion periods. Quantitative comparison of the two years with the long term means will be examined. This analysis will included in a future updated WOE TSD.

Note, the current analysis contains a portion of 2013 data. For regulatory purposes, an entire calendar year must be completed to be included in the calculation of a baseline design value period. Therefore, at the time of submittal of the 24-hour $PM_{2.5}$ SIP, calendar year 2013 couldn't be officially used in the calculation.

MTSD - 18

Unmonitored Area Analysis, p. 4.3-45. "We then compare the FDV at each grid-cell to the NAAQS (35~g/m3)." The highest scale level shown on Figure 1.25, p. 4.e-48 is 35.5 to 39.0; should the text actually state" ... at each grid-cell to the NAAQS (35.4~g/m3)"?

Response to MTSD - 18

Stating the NAAQS as anything other than 35 μg/m^3 might be confusing since that's how it's most commonly stated. However, given that the sentence quoted in the comment might be ambiguous, the sentence quoted in the comment has now been modified to read:

> "We then compare the FDV (rounded to the nearest 1 ug/m3) at each grid-cell to the NAAQS (35 μg/m^3)."

MTSD - 19

Figure 1.25, p. 4.e-48. The description of the figure indicates that only one grid cell, just NE of the Kennecott Bingham Canyon mine, shows a 2019 unmonitored modeled violation. From the color scale, however, it appears that 2 grid cells in Box Elder County, probably at the ATK location, could also be the 35.5 to 39ug/m3 color. Perhaps peak modeled concentration in each county could be tabulated?

Response to MTSD - 19

There is only one grid-cell, in the entire modeling domain, which exceeds the NAAQS according to our UAA procedure. The second and third highest FDV's are in Box Elder County (34.6 μg/m^3, 34.4 μg/m^3)

and are likely the two grid-cells being referred to in the comment. The color scheme/bar of Figure 1.25 will be modified in future work to more clearly distinguish exceedances from non-exceedances.

MTSD - 20

Section 1.8. Could more clarification be provided on how MATS is treating the non-winter days of Table 1.11 and 1.12? Are any RRFs for any species applied to these data by MATS (other than an RRF of 1.0)? If so, which species have RRFs different from 1.0, and what speciation profiles are used for the non-winter days? If RRF outside winter months are all 1.0, please add that for clarity.

Response to MTSD - 20

For clarity, the following statement to the TSD (section 4d) has been included:

> "Since we don't model any days during the months April through September, we equate RRFs, for all $PM_{2.5}$ species, to 1.0 for the two "summer" quarters that encompass these six months."

There are no exceptions with regards to the above statement. The integration of speciation profiles from "summer" quarters may play a role in determining FDV's depending where observed peak summer values occur during each year in our 5-year window. Please note that RRF's are not manually set to 1, but this necessarily results from duplicating "winter" base-year episodic CMAQ output for "summer" base/future-years.

EMISSIONS INVENTORY

[All comments in this section were submitted by EPA Region 8]

EI-1: "An analysis of 2010 emissions is also warranted because the state used projections from the 2008 triennial inventory to develop the 2010 inventory. An analysis should be done to determine if the projected emissions were consistent with actual emissions that occurred in 2010."

Response to EI-1: The 2010 baseline inventory was developed by projecting the 2008 baseline inventory using REMI growth factors. An analysis was performed comparing projected 2010 emissions with 2010 actual emissions. However, since 2010 was not a tri-annual year, not all sources in the non-attainment area were required to submit an actual inventory in 2010. Therefore, it was only possible to compare the emissions for the sources in the non-attainment area that had submitted a 2010 emissions inventory. In addition to this it was also decided that a straight line analysis between the 2008 and 2011 actual inventories should be performed since each was a tri-annual year and therefore contained inventories from all sources in the non-attainment area. Both analyses showed that the 2010 projected inventory contained higher emissions overall than the 2010 actual inventory. UDAQ feels that the method of projecting from the 2008 baseline inventory to establish the 2010 baseline inventory using REMI maintains consistency since the projection years of 2014, 2017, and 2019 were developed using the same process. Also, emissions for 2010, 2014, 2017, and 2019 were all developed using the 2008 baseline emissions inventory. If the projected emissions for the 2010 baseline were overestimated, as the analyses tends to show, then the projected emissions for the future years of 2014, 2017, and 2019 were likely overestimated as well. This eliminates any bias that may have been introduced due to using higher emissions in the 2010 baseline inventory. UDAQ also feels that modeling higher baseline emissions in 2010 is a more conservative approach.

EI-2: We have asked the state on numerous occasions to provide an output of the SMOKE model for the episodic days modeled. The EPA just received the information and we have not as yet, reviewed the data. Our review of the technical support document prior to receiving the SMOKE data and the state's air quality web site has shown daily emission amounts for categories rather than individual sources. The state provides a daily emission rate by category, i.e. point, area, road and non-road sources but does not provide point source inventories showing each source's daily emissions. We will compare the emission inventory we recently received for consistency within the larger emission inventory in the SIP and with emissions limitations indicated in the SIP.

Response to EI-2: As stated in the comment, the requested SMOKE point source reports have been delivered to the EPA. Also, please note that plant specific emissions have been tallied and reported in our publicly available SIP narrative (Table 6.3).

MOBILE

[All the comments in this section were submitted by EPA Region 8]

MOB – 1: EPA states that an I/M program in Box Elder and Tooele counties would have resulted in NOx and VOC emissions reductions. EPA has asked UDAQ to provide the estimated emissions reductions associated with such a program.

Response to MOB-1: UDAQ agrees with EPA that UDAQ needs to provide a more comprehensive analysis that led to the determination that I/M programs in Tooele and Box Elder Counties have no effect on the 24-hr PM2.5 concentrations at the Hawthorne monitoring site, which is the controlling monitor for the Salt Lake-Clearfield-Ogden non-attainment area. UDAQ will provide the modeling analysis in an updated version of the Modeling Weight-of-Evidence TSD.

MOB – 2: The SIP narrative in the Transportation Section on page 59 states: "The plans and programs produced by the transportation planning process of the [Wasatch Front Regional Council] WFRC are required to conform to the on-road mobile source emissions budgets established in the SIP. Approval of conformity is determined by the FHWA and FTA." EPA would like to change the last sentence to read: "Approval of conformity is determined by the FHWA and FTA after receipt of concurrence on the conformity determination by EPA."

Response to MOB-2: UDAQ agrees with EPA and will make the appropriate change in the Transportation Section on page 59 of the SIP narrative.

MOB – 3: EPA is concerned that there may be discrepancies between Vehicle Miles Traveled (VMT) data developed by the Metropolitan Planning Organization (MPO), the Wasatch Front Regional Council (WFRC), for use in the SIP and those VMT data used in the latest (August 22, 2013) conformity determination performed by the WFRC. EPA further states: “This potential issue of inconsistent data for VMT would have impacts on the MOVES modeling performed by the UDAQ to develop mobile sources emissions estimates for inventory data tables, the dispersion modeling, and for defining the respective non-attainment area Motor Vehicle Emissions Budgets (MVEBs).” With regard to the MVEBs, EPA would like clarification as to why the PM2.5 emissions in the SIP for the year 2014 and 2019 are lower than those emissions reported the conformity determination for the year 2015 and 2020, respectively. EPA would like clarification as to why the NOx emissions in the SIP for the year 2014 and 2019 are higher and have a different rate of decline than those emissions reported the conformity determination for the year 2015 and 2020, respectively. EPA wants UDAQ to provide the specific location in the TSD for the VMT data used within the PM 2.5 SIP.

Response to MOB-3: It is important to note that – as per the Utah State Implementation Plan Section XII, Transportation Conformity Consultation – UDAQ does not develop mobile source emissions and VMT projections for the urbanized areas covered by the MPOs. UDAQ is only responsible for developing mobile source emissions inventories and VMT for the rural counties. The VMT and emissions projections for Box Elder, Davis, Salt Lake, Tooele, and Weber counties were provided by the Wasatch Front Regional Council (WFRC) MPO.

In response to EPA's comment, WFRC states that for the latest version of the 2019 mobile source inventory requested by UDAQ for inclusion in the PM2.5 SIP for the Salt Lake City PM2.5 non-attainment area, WFRC made some assumptions regarding demographic data based on recent data that was received from the Governor's Office of Management and Budget (GOMB). UDAQ requested the updated emissions inventory for 2019 in anticipation that the revised inventory would help move the SIP closer to a successful attainment demonstration. Based on more recent economic conditions, the revised demographic data shows lower projections for 2020 employment and population than previous forecasts from the GOMB. Because this data is new, it has yet to be incorporated into the WFRC Travel Demand Model (TDM) at the Traffic Analysis Zone (TAZ) level. This is a time consuming formal review process involving WFRC staff in communication with the communities in the region to properly allocate the revised demographic data. Absent this level of detailed demographic data, WFRC applied a post model adjustment to the results of the TDM (which uses the existing demographic details) to estimate the impact of the new demographic data at the county level.

In the request for revision to the 2019 projections, UDAQ did not request, nor did WFRC provide revisions to the 2014 and 2017 projections previously submitted to the UDAQ.

TSD Section 3.e.iii pages 3-6 contain county specific emissions and VMT totals for the years 2010, 2014, 2017, and 2019 for the Salt Lake, Provo, and Logan non-attainment area SIPs as detailed below:

Summary of Base Year (2010) and Projection Year (2014, 2017 and 2019) Inventories	Pages 3-6
2010 Winter Weekday Emissions (Tons per Winter Weekday)	Page 3
2014 Winter Weekday Emissions (Tons per Winter Weekday)	Page 4
2017 Winter Weekday Emissions (Tons per Winter Weekday)	Page 5
2019 Winter Weekday Emissions (Tons per Winter Weekday)	Page 6

MOB-4: EPA would like to see the specific VMT data used for the mobile source emission estimates for 2014, 2017, and 2019 for the Salt Lake PM2.5 non-attainment area. EPA references TSD Section 3.e.iii and wants clarification as to whether the term "Distance" represents the whole-county sum total of VMT for each county listed. EPA would like an explanation as to why the VMT estimates in SIP for 2019 are lower than those for 2017 for all counties and in some counties are even less than those reported in 2014. EPA also noted VMT inconsistencies submitted by WFRC between the SIP and the WFRC August 2013 Transportation Conformity Determination.

Response to MOB-4: As noted in the response to Issue #3 above, TSD Section 3.e.iii pages 3-6 contain county specific emissions and VMT totals for the years 2010, 2014, 2017, and 2019 for the Salt Lake, Provo, and Logan non-attainment area SIPs as detailed below:

Summary of Base Year (2010) and Projection Year (2014, 2017 and 2019) Inventories	Pages 3-6
2010 Winter Weekday Emissions (Tons per Winter Weekday)	Page 3

The VMT data in the TSD under Section 3.e.iii is located in the column labeled "Distance." The term "Distance" is a term from the EPA Motor Vehicle Emission Simulator model (MOVES) and is the same as Vehicle Miles Traveled (VMT). The emissions and distance (aka VMT) reported in this table are created directly from the EPA MOVES model.

As indicated in the response to Issue #3 above, in the request for revision to the 2019 projections, UDAQ did not request, nor did WFRC provide revisions to the 2014 and 2017 projections previously submitted to the UDAQ.

As we now consider the additional planning requirements of subpart 4, there are a number of areas in which these draft SIPs will have to be supplemented or revised.

DAQ must address these subpart 4 issues in two steps. First, it will be necessary to submit a moderate-area SIP that (as now proposed) to includes an attainment date of December 31, 2015. The plan revision will be due on December 31, 2014. Second, it will likely be necessary to submit a serious-area SIP (likely due in 2017) that appears to include an attainment date of December 31, 2019.

As DAQ looks forward to the serious-area planning requirements, some of the determinations made with regard to control measures, including MVEBs, in these draft SIPs will have to be re-evaluated. Given these forthcoming planning requirements, we see no value in correcting inventories (namely 2014 and 2017) that will not be required in either SIP under subpart 4 at this time.

MOB-5: The EPA submitted comments on the proposed amendments to "Salt Lake County Health Department, Health Regulation #22 - Vehicle Emissions Control Program" on November 20, 2013. EPA comments identified a number of areas of concern with the provisions in the proposed regulation and with Appendix A of the regulation. EPA noted that emission reductions credit from the County's motor vehicle inspection and maintenance regulation were used in the modeling inventories for 2014, 2017 and 2019. Therefore, if the County does not address our concerns in its final, adopted version of county Regulation #22, EPA may be unable to approve the amended regulation, and this would affect the approvability of the SIP as a whole.

Response to MOB-5: UDAQ is aware of EPA's concerns with Salt Lake County’s proposal and have been working with Salt Lake County Health Department to address EPA's concerns.

I) Comments on the Utah County Section of the SIP Narrative: Utah County; Control Measures for Area and Point Sources, Fine Particulate Matter, PM2.5 SIP for the Provo, UT Non-attainment Area.

MOB-6: The SIP narrative in the Transportation Section on page 58 states: "The plans and programs produced by the transportation planning process of the MAG are required to conform to the on-road mobile source emissions budgets established in the SIP. Approval of conformity is determined by the FHWA and FTA." EPA would like to change the last sentence to read: "Approval of conformity is determined by the FHWA and FTA after receipt of concurrence on the conformity determination by EPA."

Response to MOB-6: UDAQ agrees with EPA and will make the appropriate change in the Transportation Section on page 58 of the SIP narrative.

MOB-7: EPA notes a potential VMT inconsistency between the data submitted by the Mountainland Association of Governments (MAG) for 2019 in the SIP and for 2020 in the 2009 MAG Conformity Determination. In addition, EPA would like to see the specific VMT data used for the mobile source emission estimates for 2014, 2017, and 2019 for the Utah PM2.5 non-attainment area.

Response to MOB-7: As noted above in the discussion regarding the Salt Lake SIP, it is important to note that – as per the Utah State Implementation Plan Section XII, Transportation Conformity Consultation – UDAQ does not develop mobile source emissions and VMT projections for the urbanized areas covered by the MPOs. UDAQ is only responsible for developing mobile source emissions inventories and VMT for the rural counties. The VMT and emissions projections for Utah county were provided by Mountainland Association of Governments (MAG) MPO .

In response to EPA's comment, MAG states that conformity determination is required, at a minimum, every four years in preparation of a new or updated Long Range Plan (LRP) or Regional Transportation Plan (RTP). The MAG RTP quoted was adopted by MAG's Regional Planning Committee in May 2011, received its concurrence in June 2011, but was under development since 2009 with networks and demographics current at the time and during a highly recessionary period. The SIP MAG transportation data were prepared in late-2012 with the benefit of four years since the conformity determination report, updated census data, and demographics appropriate for the county that has kept its position as the 3rd fastest growing in the nation.

In addition, MAG is puzzled by the association of conformity data to SIP development, and notes that the Clean Air Act SIP development rules do not require use of conformity data to develop a SIP. MAG also notes that its conformity determination has to come from a fiscally constrained plan that is limited only to proven available funds while no such restriction is mentioned for the development of a SIP

Because UDAQ has determined that a positive attainment demonstration was achieved with the inventories MAG submitted, MAG does not see a conflict.

TSD Section 3.e.iii pages 3-6 contain county specific emissions and VMT totals for the years 2010, 2014, 2017, and 2019 for the Salt Lake, Provo, and Logan non-attainment area SIPs as detailed below:

Summary of Base Year (2010) and Projection Year (2014, 2017 and 2019) Inventories	Pages 3-6
2010 Winter Weekday Emissions (Tons per Winter Weekday)	Page 3

MOB-8: EPA would like further explanation on how the MVEB trading ratios were developed for the Provo non-attainment area. It is EPA expectation that there should be a higher MVEB trading ratio for VOC than NOx, but the ratios provided by UDAQ show a higher ratio for NOx.

Response to MOB-8: UDAQ developed the trading ratios for the Provo non-attainment area with the same methods as the Salt Lake and Logan non-attainment areas. The method involves CMAQ modeling sensitivities patterned after the methods used by the South Coast Air Quality Management District's 2012 Air Quality Management Plan (http://sfdev.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2012-air-quality-management-plan/final-2012-aqmp-carb-epa-sip-submittal-(december-2012)/2012-aqmp-carb-epa-sip-submittal-appendix-v.pdf?sfvrsn=2). The South Coast method is described starting on page 264 of the linked document.

UDAQ performed 3 separate model sensitivities to 2019 control emissions inventory in the Provo non-attainment area. They are the following:

1. Removed 1 ton per day of NOx emissions from the Provo non-attainment inventory. This 1 ton per day reduction of NOx leads to average reduction in the overall 24-hr PM2.5 of 0.318 ug/m3 at the Lindon monitoring site.
2. Removed 1 ton per day of VOC emissions from the Provo non-attainment inventory. This 1 ton per day reduction of VOC leads to average reduction in the overall 24-hr PM2.5 of 0.566 ug/m3 at the Lindon monitoring site.

3. Removed 1 ton per day of direct PM2.5 emissions from the Provo non-attainment inventory. This 1 ton per day reduction of PM2.5 leads to average reduction in the overall 24-hr PM2.5 of 3.579 ug/m3 at the Lindon monitoring site.

To establish the MVEB ratios, simple division was applied between the model sensitivity results:
NOx:PM2.5 trading ratio = 3.579/0.318 ~ 11.26
VOC:PM2.5 trading ratio = 3.579/0.566 ~ 6.33

The VOC trading ratio is lower than the NOx trading ratio for the Provo non-attainment area simply because the model suggests that reductions in VOC emissions are more efficient in reducing overall PM2.5 than NOx emissions.

II) TSD Comment:

MOB-9: EPA points out that UDAQ claims Federal Control of Tier III as part of the On-Road Mobile Sources RACM analysis under TSD section 5.e page 5.e.1.

Response to MOB-9: UDAQ mistakenly included reference to Tier III as part of the RACM analysis. UDAQ will remove the reference to Tier III from the TSD.