PM_{10} SIP/Maintenance Plan Evaluation Report: Big West Oil, LLC

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
Big West Oil Refinery

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the Utah Implementation Plan (SIP); to address the Salt Lake County PM_{10} Nonattainment Area (SLCNA). This document specifically serves as an evaluation of the Big West Oil Refinery.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Sections IX.H.1-4 of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report. However, see Section 7.0 of this document for some clarification.
- When referencing the original SIP with an effective date of August 8, 1994 the qualifier $^{\{OS\}}$ will follow any citation from that document.
- In reference to the updated Utah County SIP with an effective date of January 22, 2003 the qualifier $^{\{UC\}}$ will follow any citation from that document.
- When referencing any new Maintenance Plan/SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Big West Oil Refinery
Address: 333 W. Center Street, North Salt Lake, Utah, Davis County
Owner/Operator: Big West Oil, LLC
UTM coordinates: 4,521,000 m Northing, 422,500 m Easting, Zone 12

1.2 Facility Process Summary

The Big West Oil Refinery is a petroleum refinery capable of processing 30,000 barrels per day of crude oil. The source consists of a FCCU, catalytic reforming unit, hydrotreating units, and a sulfur recovery unit. The source also has the usual assorted heaters, boilers, cooling towers, storage tanks, flares, and fugitive emissions. The source does not operate with flare gas recovery or cogeneration processes.

1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of the main emitting units from the Big West Oil Refinery (BWO):

FCC Heater
Alkylation Unit Deisobutanizer Reboiler Heater
#2 Crude Heater
Crude Preflash Heater
#1 Crude Heater
Vacuum Heater
Unifiner Heater
Reformer Heaters
(MIDW) Heater
Hydrodesulfurization (HDS) Reboiler
HDS Heater
Sulfur Removal Unit/Plant (SRU) and Tail Gas Incinerator
FCC Regenerator Combustion Gas Vent
#1 Boiler
#2 Boiler
#6 Boiler
Plant Flare #1
Plant Flare #2
VCU: Railcar Loading Facility and Vapor Combustor Unit
Standby (Emergency) Fire Pump
Cooling Towers
Fugitives
Tank Farm

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at the refinery, rather it is a listing of all significant emission units or emission unit groups (such as the tank farm).

1.4 PM2.5 SIP New Equipment

As part of the RACT requirements for the PM2.5 SIP, BWO is in the process of making equipment upgrades which will be completed prior to the attainment demonstration date of the new maintenance plan (January 1, 2019). Although these upgrades are not yet installed, and therefore are not in the equipment list included in Section 1.3 above, the new equipment has been included in the modeled attainment demonstration; by including the effects of the equipment on total emissions from the refinery.

BWO is adding two new control devices: a Flue Gas Filter System, also known as a Pall Filter, to control particulate emissions from the FCCU; and a redundant caustic fuel gas scrubber, to extract H2S from fuel gas during outages of the amine unit and/or SRU. Both of these systems

are included in the emission calculation spreadsheet used as primary input for the attainment demonstration model. The flue gas filter system controls primary particulate emissions from the FCCU, perhaps the largest single particulate source located at the refinery. The caustic scrubber serves to prevent excess emissions during so-called "turnaround" events (discussed in greater detail in Sections 2 and 3 below), allowing the refinery to operate within its daily emissions Cap even during periods of SRU maintenance or extended malfunction.

One additional control system is the requirement to install and operate a flare gas recovery system or equivalent flare gas minimization process. This system must be installed an operational no later than January 1, 2019 – again, before the attainment demonstration date. The requirement for this system is found within the refinery general requirements of Section IX.H.11 of the SIP, specifically IX.H.11.g.v.B. Although no equivalent requirement was brought forward into the PM10 Section of the new maintenance plan, BWO (as with all the refineries) does have additional requirements in its listing in Section IX.H.2 to account for monitoring of flare gas flow – either to demonstrate flare gas recovery, or to account for flaring emissions as part of the overall daily Caps. The monitoring requirements will address both PM10 and PM2.5 needs. See Items 5 and 6 below for additional details.

1.5 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, Big West Oil's baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	55.10
SO_2	188.71
NO_x	195.77

The current PTE values for Big West Oil, as established by the most recent AO issued to the source (DAQE-AN101220066-15) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	71.0
SO_2	712.5
NO_x	396.7

However, please see Table 3 below for further details on BWO's true PTE value.

2.0 Modeled Emission Values

Unlike the base year inventory, which used only the 2011 actual emissions for each source to set the baseline for modeling, a modified version of the PTE values was used for the modeled attainment demonstration. Beginning with the PTE values listed in Table 2 (from the most recent approval order issued to BWO in 2015), these emissions were then "trued-up" by including the expected effects from implementation of RACT from the $PM_{2.5}$ SIP. This true-up yields a 2019 Projected Emission Value for each of the pollutants of concern. Where necessary, these values were further corrected for condensable particulates using simple correction factors based on fuel consumed or process type.

Where gaseous fuels, such as natural gas or refinery fuel gas, were combusted, filterable-only emissions were converted to a filterable+condensable emission value by multiplying the filterable rate by 4 (see explanation in section 3.3 of this document under the subheading of "Basis for the PM_{10} Emission Limitations"). Liquid fuels, such as diesel fuel #2, were converted using the latest AP-42 emission factors. Processes such as cooling towers, which emit largely filterable-only emissions, were not adjusted. Other processes were adjusted, as needed, on a case-by-case basis using the best data available – primarily the latest stack test information.

For the Big West Refinery, this yielded the following modeled emission values – summarized in Table 3.

Table 3: Modeled Emission Values

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	190.79
SO_2	140.0
NO_x	195.0

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the December 3, 2014 $PM_{2.5}$ Section of the SIP (IX.H.11-13). This section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM_{10} SIP sources – including the refineries in general, and the Big West Oil Refinery in specific. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11-13 – which comprise the $PM_{2.5}$ sections of the SIP, and include this additional RACT application. All requirements from the original PM_{10} SIP that have not been superseded or replaced, and which are still necessary, will also be retained. By necessary, meaning: significant from the standpoint of PM_{10} control, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

BWO is a previously listed SIP source. In the original PM_{10} SIP, BWO was listed in Subsection IX.H.2.b.N$^{\{OS\}}$ as Flying J. Inc., - North Salt Lake. As a listed source there were several requirements and conditions that applied to the facility.

In addition, BWO is also a listed source in the $PM_{2.5}$ Section of the SIP (see SIP Section IX.H.12.b). As was discussed above in Item 2.0, all limits in this maintenance plan are based on the limits in the December 3, 2014 $PM_{2.5}$ SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.b. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below:

3.1 Original SIP General Requirements

IX.H.2.a General Requirements$^{\{OS\}}$

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a$^{\{OS\}}$ applied to the listed sources found in Utah County, while those found at IX.H.2.a$^{\{OS\}}$ applied to the listed sources found in Salt Lake and Davis County. As

the then Flying J Refinery is located in Davis County, only the general requirements of IX.H.2.a{OS} applied. However, except for the additional requirements found under IX.H.2.a.M{OS} for petroleum refineries and the specific fuel requirements of IX.H.2.a.N{OS}, the two subsections are essentially identical.

2.a.A. Stack Testing{OS} – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which serves the same purpose.

2.a.B. Visible Emissions{OS} – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which serves the same purpose.

2.a.C. Visible Emissions (cont.){OS} – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.D. Annual Emission Limitations{OS} – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists, and no source-specific annual SIP Caps appear in either IX.H.2 or IX.H.3 of the new maintenance plan.

2.a.E. Recordkeeping Requirements{OS} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders{OS} – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance{OS} – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program, under R307-401-4(1).

2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program, under R307-401-3(1)(b).

2a.I. Unpaved Operational Areas{OS} – established rules for treating fugitive dust with water sprays or chemical dust suppression. This requirement has been superseded by the fugitive dust rules of R307-205 and R307-1-4.5, or the most recent federally approved fugitive dust rule.

2.a.J. Actual Emissions{OS} – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsections IX.H.1-4 of the SIP. This requirement is outdated and obsolete.

2.a.K. Test if Directed{OS} – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test

frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions{OS} – established that the definitions contained in R307 apply to subsection IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.N. Specific Fuel Requirements for Coal and/or Oil{OS} – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded by the individual source requirements found in IX.H.2 and IX.H.3 (see specifically the sources Kennecott and BYU). This requirement is now largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources have the ability to burn any other fuel oils.

3.2 Original SIP Petroleum Refinery Requirements

2.a.M. Petroleum Refineries{OS} – This is a fairly lengthy subsection pertaining only to the petroleum refineries. This subsection has its own sub-subsections, owing to the overall length and complexity.

2.a.M.A. Sulfur Recovery Units (SRUs){OS} – established the requirement for 95% efficient SRUs, no burning of liquid fuel oil except during natural gas curtailments, use of low-SO_x catalyst to attain a 9.8 kg SO_2/1000 kg coke burnoff in FCC units, amine and sour water overhead streams shall also be processed in the SRU. These conditions currently remain in effect. The SO_2 limit is largely irrelevant as the limitation in SIP subsection IX.H.1.g.i.A.I is based on 40 CFR 60, Subpart Ja, and is more stringent. The other three requirements: 95% efficient SRUs, no burning of liquid fuel oil, & amine and sour water overhead streams being processed in the SRU, shall be retained. These three conditions are found at SIP subsections IX.H.1.g.iii, IX.H.1.g.iv, and IX.H.1.g.iii, respectively.

2.a.M.B. Routine Turnaround Periods{OS} – established exclusion periods when routine turnarounds of the SRUs could be performed, and the procedure for scheduling one of these periods. These conditions are no longer required. Each of the refineries has agreed to incorporate alterative language which supersedes these requirements. In BWO's specific case, the refinery has opted to simply include SRU turnaround emissions within the existing 24-hour emission Caps – including all flaring and additional SO_2. This is accomplished through the installation of redundant equipment, specifically a caustic scrubber to serve as a backup for the SRU.

2.a.M.C.1. Compliance Demonstration part 1{OS} – established that SRU turnaround emissions and flaring emissions are not included in either the daily (24-hour) or annual compliance demonstrations. As with 2.a.M.B{OS} above, this requirement is no longer required. Each refinery has agreed to alternative language regarding SRU turnarounds (see the discussion on 2.a.M.B{OS} above). All flaring emissions have been included in the 24-hour emission Caps for each listed refinery.

2.a.M.C.2. Compliance Demonstration part 2{OS} – established how the daily (24-hr) emissions limits (Caps) would be determined, including recordkeeping and reporting requirements. This subsection has since been superseded by the individual source's SIP

subsection (for Big West Oil, this would be Section IX.H.2.a) which establishes the 24-hour emission limits, and the monitoring, recordkeeping and reporting requirements associated with those limits.

2.a.M.C.3. Compliance Demonstration part 3{OS} – established a methodology for how emission limits could be modified/adjusted as necessary. This subsection is no longer required, as this procedure is no longer followed.

2.a.M.C.4. Compliance Demonstration part 4{OS} – also established that annual emissions for refineries followed a process essentially identical to the rolling 12-month process outlined above in 2.a.D{OS}. This subsection is no longer required as the specific requirement to track annual emissions is no longer needed with the removal of the annual PM_{10} standard.

2.a.M.D. Process Flaring Emissions and Routine Turnaround Emissions{OS} – established that both sets of emissions were included in the modeled attainment demonstration. This subsection is no longer required, as a new attainment demonstration has been performed and both process flaring and routine turnaround emissions are handled differently in the new maintenance plan. As has been discussed above, process turnarounds (a term applied specifically to operation of the SRU) are now addressed by each individual refinery by incorporation of the turnaround within the daily Cap emission limits. Similarly, process flaring emissions are also included by default as the language which previously excluded these emissions has been removed.

3.3 Original SIP Source Specific Requirements

Individual source requirements:

2.b.N.1.{OS} This subsection was a listing of the equipment at the refinery – this subsection has been superseded and is irrelevant. A simple listing of equipment does not constitute an emission limitation, does not impose any restriction on daily emissions, and rapidly becomes out of date as well as impossible to enforce. The original listing found in this subsection does not match the current equipment installed and operating at the refinery and would represent a significant step backwards in emission control and refining technology.

2.b.N.2.{OS} Basis for SO_2 Emission Limitations – A) established the SO_2 daily and annual emission Caps. There were two different daily Caps: a smaller "wintertime" Cap between October 1 and March 31, and a larger "summertime" Cap between April 1 and September 30. The annual and daily caps also excluded the contribution from the SRU tailgas incinerator. B) established the sources included in the SO_2 emissions Caps. C) established that the SO_2 emission Caps shall be determined by multiplying the amount of each type of fuel burned each day by specific emission factors listed in this subsection [2.b.N.2.C){OS}.], and that the quantity of each fuel burned would need to be monitored/recorded appropriately. D) was supposed to establish individual point source limitations for the SRU tail gas incinerator (these were never revisited in the context of the original SIP). E) established that stack testing on the "non-capped" sources would be performed as outlined in SIP subsections 2.b.N.5{OS}, 2.a.A{OS} and 2.1.M{OS}. F) established that the plant flare and TCC separator surge drum were not included in the SO_2 Caps, and also not regulated for SO_2 emissions.

This subsection has since been superseded by the SIP subsection which establishes new plantwide SO_2 daily (24-hour) emission Caps (for Big West Oil, this would be Section IX.H.2.a.iii). These new SO_2 emission Caps cover all emission units at the refinery – including the flares – so no

emission unit is excluded. The new 24-hour SO_2 emission Cap is significantly lower than the original Cap (see the comparison table below). Although there is no PM_{10} annual standard, the comparison in Table 4 also lists the annual emission estimate for easy comparison with the original SIP. The compliance methodology in SIP subsection IX.H.2.a.iii is based on the original method of measuring/monitoring the amount of fuel burned multiplied by the emission factor for each fuel type – although these emission factors have been updated as needed. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below).

2.b.N.3.{OS} Basis for the NO_x Emission Limitations – Similar to the SO_2 limitations above: A) established the NO_x daily and annual emission Caps. As with SO_2, there are two different NO_x daily Caps: one winter, and one summer Cap; following the same time periods established under SO_2. B) established the sources included in the NO_x emissions Caps. C) established that the NO_x emission Caps shall be determined by multiplying the amount of each type of fuel burned each day by specific emission factors listed in this subsection [2.b.N.3.C){OS}.], and that the quantity of each fuel burned would need to be monitored/recorded appropriately. D) established that the plant flare and TCC separator surge drum were not included in the NO_x Caps, and also not regulated for NO_x emissions.

This subsection has since been superseded by SIP subsection IX.H.2.a.ii which establishes new plantwide NO_x daily (24-hour) emission Caps. As with the SO_2 emission Caps, these new NO_x emission Caps cover all emission units at the refinery – including the flares. The new NO_x daily emission Cap is also lower than the original Caps (Table 4 includes the expected annual emissions of NO_x for comparison with the original SIP). Again, the compliance methodology included in SIP subsection IX.H.2.a.ii uses the amount of fuel burned multiplied by the emission factor for each fuel type. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below).

2.b.N.4.{OS} Basis for the PM_{10} Emission Limitations – As with both the SO_2 and NO_x limitations listed above: A) established the PM_{10} daily and annual emission Caps. Again, there are two seasonal 24-hour Caps, following the same monthly schedule as previously laid out. B) established the sources included in the PM_{10} emissions Caps. C) established that the PM_{10} emission Caps shall be determined by multiplying the amount of each type of fuel burned each day by specific emission factors listed in this subsection [2.b.N.3.C){OS}.], and that the quantity of each fuel burned would need to be monitored/recorded appropriately. D) established an individual point source limitation for the TCC separator surge drum. E) established that the plant flare and the reformer compressors were not included in the PM_{10} Caps, and also not regulated for PM_{10} emissions.

This subsection has since been superseded by SIP subsection IX.H.2.a.i which establishes a new plantwide PM_{10} daily (24-hour) emission Cap. As with both the SO_2 and NO_x emission Caps, this new PM_{10} emission Cap covers all emission units at the refinery – including the flares. As before, the compliance methodology included in SIP subsection IX.H.2.a.i uses the amount of fuel burned multiplied by the emission factor for each fuel type. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below).

Table 4: Comparison Table – Old SIP Caps vs New SIP Caps

	SO_2 Original	**SO_2 New**	**NO_x Original**	**NO_x New**	**PM_{10} Original**	**PM_{10} New**

Annual	824.8	140.0	278.7	195.0	22.0[$%]	190.79[&]
Daily (24-hr)[*]	3.779 / 2.904	0.60	1.041 / 0.923	0.80	0.122 / 0.112[$]	0.763[&]

[*] values listed are Apr 1 – Sept 30 / Oct 1 – Mar 31
[$] filterable emissions only
[%] PM_{10} Cap source emissions were limited to 7.30 tons annually
[&] includes condensable emissions

The PM_{10} emission Cap appears larger than the original SIP emission values. However, there are two mitigating factors that must be taken into account. First, when the original SIP was being prepared, only filterable PM_{10} was considered and set as part of the emission limits for each listed source. Without consideration of condensable particulate emissions, this could greatly underestimate the potential contribution from any particular source. The Big West Refinery is primarily fired on a combination of natural gas and refinery fuel gas. From both AP-42 and recent stack testing, the emission factors for these fuels are equivalent and are as follows:

Filterable PM: 1.9 lb/10^6 scf
Condensable PM: 5.7 lb/10^6 scf
Total PM: 7.6 lb/10^6 scf

This shows that when condensable PM_{10} is taken into account, the total PM_{10} is almost exactly four times the filterable value alone. Secondly, during the calculations for the original SIP technical support documentation, an error was made that cut the amount of PM_{10} allocated to the Flying J Refinery in half. The 22 tons per year value should have been 44 tons per year. When both of these factors are taken into account, total PM_{10} emissions have remained essentially unchanged. Daily (24-hour) emissions have actually decreased slightly, even using the more conservative "summertime" value as show below:

0.112 * 2 (adjustment for allocation error) * 4 (adjustment for condensables) = 0.896 tons per day

As no allowance was made for cooling towers or other non-combustion sources, the adjustment methodology is reasonable for a rough comparison.

2.b.N.5.{OS} Stack Testing Requirements – established which point sources were required to comply with specific emission limitations (Plume Burner, TCC separator surge drum, SRU tail gas incinerator), the test method to be used to verify compliance (including CEMs if applicable), and the frequency of testing and/or monitoring.

This subsection has since been superseded by SIP subsection IX.H.2.a which establishes new monitoring, recordkeeping and reporting requirements for each of the limits listed in that subsection. The test methods to be used for each specific pollutant are listed in subsection IX.H.1.c. Details on the use of CEMs is covered in subsection IX.H.1.f.

2.b.N.6.{OS} Annual Emissions – established total annual emissions for the entire refinery. These annual emissions differed from the SIP Cap totals in one important aspect; the SO_2 total included values for SRU annual maintenance (39.8 tpy. Thus, total annual SO_2 emissions were established at 864.6 tons/yr. There was also a small allowance of 0.06 tons of PM_{10}, 4.0 tons of SO_2 and 6.7 tons of NO_x for a de-waxing unit, which was planned but not yet built at the time of issuance of the original SIP.

This subsection has since been superseded by SIP subsections IX.H.2.a.i, IX.H.2.a.ii and IX.H.2.a.iii which establishes new emission Caps for each of the pollutants of concern (PM_{10}, NO_x and SO_2). These emission Caps include the potential emissions from all current emission units at the refinery, including the flares.

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference. As specifically stated in subsection IX.H.1.a below, these general requirements apply to all sources subsequently listed in either IX.H.2 (Salt Lake County) or IX.H.3 (Utah County), and are in addition to (and in most cases supplemental to) any source-specific requirements found within those two subsections.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this

subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow – either in the Petroleum Refinery provisions of IX.H.1.g, or the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – General Refinery Requirements

The new maintenance plan will incorporate several new requirements that apply specifically to those petroleum refineries listed in Sections IX.H.2 and IX.H.3 of the SIP. Some subsections of IX.H.1.g also apply more broadly and could affect additional petroleum refineries in addition to those listed in the Source Specific sections which follow. Where this greater applicability exists

for a particular condition or limitation, such will be noted in the discussion for that requirement.

IX.H.1.g.i.A This condition covers SO_2 emissions from fluidized catalytic cracking units (FCCUs). The limit is 50 ppmvd @ 0% excess air on a 7-day rolling average basis, as well as 25 ppmvd @ 0% excess air on a 365-day rolling average basis.

The condition is based on 40 CFR 60 Subpart Ja, and includes the same limitation found in that subpart. Compliance is demonstrated by CEM, as outlined in 40 CFR 60.105a(g) – also from Subpart Ja.

IX.H.1.g.i.B This condition addresses PM emissions from FCCUs. The limit is 1.0 lb PM per 1000 lb coke burned. The emission limit applies on a 3-hour average basis.

The emission limit is derived from 40 CFR 60 Subpart Ja, although Subpart Ja does not specifically state that the limit applies on a 3-hour average. Instead it states that compliance will be demonstrated via a performance test using Method 5, 5b or 5f, using an average of three 60-minute (minimum) test runs.

Compliance is demonstrated by stack test as outlined in 40 CFR 60.106(b). This stack testing procedure is from Subpart J, rather than Subpart Ja. The equations utilized and reference methods involved are identical between the two subparts; however, the protocol to follow for testing is much more direct and straightforward in §60.106(b). The condition also requires the installation of a continuous parameter monitoring system (CPMS) to monitor and record operating parameters for determination of source-wide PM_{10} emissions for inclusion in the 24-hour PM_{10} Cap (see the individual source specific requirements of IX.H.2 for details on these Caps).

IX.H.1.g.ii This condition limits the H_2S content of gases burned within any refinery located within (or affecting) an area of $PM_{2.5}$ nonattainment. The limit is 60 ppm H_2S or less as described in 40 CFR 60.102a on a rolling average of 365 days.

As the $PM_{2.5}$ nonattainment areas encompasses the entirety of the PM_{10} maintenance areas this condition potentially affects more than just the four refineries listed in IX.H.2. There is at least one minor source refinery (Silver Eagle Refinery) which is affected by this requirement. The Silver Eagle Refinery was previously listed in the original SIP as Crysen Refining, Inc., but was delisted as the source is no longer a major source.

Compliance is demonstrated through continuous H_2S monitoring, as outlined in 40 CFR 60.107a. Both the limitation and the compliance methodology are based on 40 CFR 60 Subpart Ja.

IX.H.1.g.iii This condition requires the installation of SRUs that are 95% effective in removing sulfur from the streams fed to the unit; or SRUs that meet the SO_2 emission requirements of Subpart Ja. The amine acid gas and sour water stripper acid gas shall be processed in the SRU(s).

This is part of condition 2.a.M.A$^{\{OS\}}$ brought forward from the original SIP. No other requirement has specifically superseded this condition, so the language has been incorporated herein.

Compliance shall be demonstrated by daily monitoring of flows to the SRUs (flow rate) and SO_2 concentration in the exhaust stream (via CEM). Compliance shall be determined on a rolling 30-day average. As the specific compliance methodology was never outlined in the original SIP

condition, and not clarified in any of the original specific source requirements, this requirement attempts to address this deficiency.

Small changes in the language of this condition were made to accommodate differences between the various refineries as they exist today, and to clarify the original intent of the requirement. For cases where a refinery has combined exhaust flows for control purposes, this can make monitoring of the SO_2 concentration from only the SRU exhaust highly difficult. However, past testing has demonstrated that a 95% level of control across the SRU results in SO_2 emissions in excess of the Subpart Ja emission standard. Therefore, meeting the NSPS emission standard will represent an equivalent or greater level of control. Smaller refineries, without tail gas incineration and not currently subject to Subpart Ja, are still subject to the existing minimum 95% level of efficiency. With respect to the amine acid gas and sour water stripper gas, this new language clarifies that it is the acid gas from these two processes that needs to be sent to the SRU, not all potential streams – some of which may be liquid streams which cannot be handled by the SRU.

IX.H.1.g.iv This condition disallows the burning of liquid fuel oil except during natural gas curtailments and/or as specified in IX.H.2 or IX.H.3.

This is an additional part of condition 2.a.M.A$^{\{OS\}}$ brought forward from the original SIP. As with the SRU requirement addressed in the previous condition, this condition was also never superseded. The language has been incorporated herein. Specifically disallows the burning of fuel oil in refinery heaters and boilers. Specific language in the individual source requirements of IX.H.2 (and potentially IX.H.3) allows for the use of diesel-fired emergency generators and similar emergency use equipment outside of natural gas curtailment periods.

IX.H.1.g.v This condition establishes new requirements on hydrocarbon flares.

It states that all hydrocarbon flares (defined as all non-dedicated SRU flare and header systems and all non-HF flare and header systems) are subject to Subpart Ja as of January 1, 2018 if not previously subject.

This is a simple requirement to set all the hydrocarbon flares as being subject to 40 CFR 60 Subpart Ja. It is language brought forward from the requirements of the PM2.5 SIP (Section IX.H.11.g.v.A) in order to maintain consistency between sections. Although the second paragraph of the PM2.5 SIP (IX.H.11.g.v.B) was not similarly brought forward, flare gas monitoring provisions which address the elements of that subsection can be found within each refinery's individual specific requirements of Section IX.H.2 (*see* Item 6.1 below).

5.1 Monitoring, Recordkeeping and Reporting

The new petroleum refinery requirements establish several specific emission limitations. Primarily these limits are monitored continuously – such as the SO_2 CEM on the FCCU or the H_2S monitor on fuel gas. Where continuous monitoring is used, the requirements of IX.H.1.f apply, which incorporates by reference R307-170, 40 CFR 60.13 and 40 CFR 60, Appendix B – Performance Specifications.

Under R307-170, paragraph 170-8 addresses Recordkeeping, while 170-9 addresses Reporting.

The FCCU PM limit is demonstrated by stack test. This stack test requirement is subject to the requirements of IX.H.1.e. In addition, any source with a direct stack emission limitation is

subject to the requirements of R307-165.

These conditions are also subject to the general recordkeeping and reporting requirements of IX.H.1.c.

5.2 Discussion of Attainment Demonstration

PM Discussion: While the new PM limit on the FCCU might not appear to directly affect PM_{10} emissions, this would be incorrect. The limit is derived from the current NSPS (Subpart Ja). Under the NSPS, the assumption was that all particulate captured in the reference test method (Method 5, 5b or 5f) would be considered as PM_{10}. This is still the case, as compliance with the PM limit at the FCCU shall be demonstrated by stack test. Using a method 5 variant stack test allows the test to be overly conservative, as some particulate captured may fall outside the PM_{10} size range, and still be useful for SIP planning purposes. At the same time, it lowers the regulatory burden on the sources, by allowing each source to only have to comply with the requirements of the individual NSPS. The limit is expressed on a 3-hour block average, well below the 24-hour basis of the PM_{10} standard. Stack tests are required every three (3) years, which meets the minimum stack test frequency set by DAQ. Compliance is demonstrated via monitoring and use of emission factors. Stack testing serves to periodically adjust emission factors to account for significant changes in feedstocks, refinery turnarounds, or other large-scale changes that would affect the emission factor. As allowed under R307-165-2, the Director may require stack testing at any time to demonstrate compliance.

SO_2 Discussion: This is a new limitation that did not previously appear in any form in the original SIP. Although the limit is expressed on a 7-day rolling average basis, and therefore longer than the 24-hour PM_{10} standard, SO_2 emissions are eventually converted into sulfates – the particulate form. As this process takes some time to occur, and is not directly dependent on hourly or daily SO_2 emissions – but rather on area average SO_2 concentrations and relative chemistry – a 7-day rolling average is quite adequate to demonstrate attainment with the standard. This is especially true, given the overall daily SIP Cap – which still controls total SO_2 emissions from the entire refinery. The secondary limit, expressed on a 365-day basis simply serves to keep SO_2 emissions down over the long run, as well as maintaining consistency with the $PM_{2.5}$ SIP requirements.

H_2S Discussion: Although the limit appears to be on a much longer averaging period than the 24-hour PM_{10} standard, the rolling 365-day calculation prevents the overall H_2S content from increasing. This in turn keeps the amount of sulfur being sent to each fuel burning device consistently low. This is also a fallback limit, like the SO_2 emissions from the FCCU discussed in the previous paragraph. Total SO_2 emissions are still controlled by the daily SIP Cap, regardless of the averaging period on fuel gas H_2S content.

6.0 New Maintenance Plan – Big West Oil Specific Requirements

The Big West Oil specific conditions in Section IX.H.2 address those limitations and requirements that apply only to the Big West Oil Refinery in particular.

IX.H.2.a.i This condition establishes a source-wide Cap on PM_{10} emissions on a ton per day basis. Emissions are calculated on a filterable plus condensable basis from all sources, each day. This limit is 0.763 tons PM_{10} per day.

The condition also includes the definition of a day as being from midnight until the following

midnight. Compliance 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. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.2.a.ii This condition establishes a source-wide Cap on NO_x emissions on a ton per day basis. Emissions are calculated from all emission points daily. This limit is 0.80 tons NO_x per day.

This condition includes the same definition of "day" as being from midnight until the following midnight. Compliance 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. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.2.a.iii This condition establishes a source-wide Cap on SO_2 emissions on a ton per day basis. Emissions are calculated from all emission points daily. This limit is 0.60 tons SO_2 per day.

This condition includes the same definition of "day" as both of the previous conditions as being from midnight until the following midnight. Compliance 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. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.2.a.iv This condition addresses specific fuel sulfur requirements for the refinery, allowing the use of diesel-fired emergency equipment as an exception to IX.H.1.g.iv.

Big West Oil currently has a number of small diesel-fired emergency engines listed in its AO. No specific provision has ever been made to allow for the use of diesel-fired emergency equipment at the refineries – and while it is clear that the provisions of 2.a.M.A$^{\{OS\}}$ were meant for the burning of liquid fuel in heaters and boilers and not for the application of emergency equipment, such language was not included nor brought forward. This condition (and similar conditions for the other refineries) addresses that oversight.

6.1 Monitoring, Recordkeeping and Reporting

Monitoring for all three conditions is addressed through a variety of methods, depending on the emission point in question. Stack testing, CEMs, parameter monitoring – all are viable options, and have been included in the language of IX.H.2.a.i through IX.H.2.a.iii. As appropriate, these monitoring requirements are complemented by the general provisions of IX.H: 1.e for stack testing, 1.f for CEMs and other continuous monitors, 1.c for recordkeeping and reporting.

Where necessary, additional monitoring, recordkeeping and/or reporting requirements have been directly included in the language of IX.H.2.a to address specific concerns. One example would be the use of leveling gauges on all fuel oil tanks to determine daily fuel oil consumption.

No specific monitoring, recordkeeping or reporting is required for IX.H.2.a.iv, as this condition

serves merely as a specific exception to the general refinery requirement prohibiting the burning of liquid fuel oils. Such exception is authorized under the language of IX.H.1.g.iv itself.

Flare gas monitoring requirements – under subsection IX.H.11.g.v.B of the PM2.5 SIP, each refinery, including BWO, is required to install and operate a flare gas recovery system or equivalent flare gas minimization process. This system needs to limit hydrocarbon flaring below 14,160 standard cubic meters (m3) (500,000 standard cubic feet (scf)) above the baseline established by the procedure outlined in 40 CFR 60.103a(a)(4). As the specific requirements of IX.H.11.g.v.B were not brought forward into the new maintenance plan, each refinery is required to include monitoring for flare gas such that total flare gas flow rate can be recorded on a daily basis, the daily flare gas recovered for fuel gas processing can be recorded, and an estimate of daily flare gas emissions can be made. All flaring emissions are included in the daily emission Caps, and monitoring of flare gas flows satisfies both the requirements of demonstrating compliance with the daily Caps as well as subsection IX.H.11.g.v.B.

6.2 Discussion of Attainment Demonstration

Generally, the calculation methodology for determination of daily (24-hr) source-wide emissions from the Big West Oil refinery is identical to the method used in during the 1991/1992 timeframe of the original SIP. However, several key differences exist:

1. Emissions in the new maintenance plan are lower than in the original SIP

As is shown above in Table 3, the daily SIP Caps have dropped for all pollutants with the exception of PM_{10}. PM_{10} emissions have increased primarily because of the addition of condensable emissions which were never accounted for in the original SIP. See further discussion in Item 6.2.3 below.

2. All emission units/emission points are included in the new maintenance plan

The original SIP was based on a concept of “SIP Cap sources”, where only certain specific sources were included as contributing toward the emission total for a particular pollutant. Other sources, such as the flares or the compressors, would be specifically excluded from counting towards this total. This would even be spelled out by a specific requirement in the original SIP. The new maintenance plan eliminates this concept by simply stating that all sources are included, and that the emission “Caps” apply source-wide.

3. Condensable emissions, which were excluded from the original SIP, are included in the new maintenance plan

The original SIP was based on filterable PM_{10} emissions only. The new maintenance plan includes both filterable and condensable PM_{10} emissions. The 24-hour source-wide PM_{10} limit listed in IX.H.2.a.i clearly states that condensable emissions are included from all sources, and the emission factors listed in that condition include values for condensable emissions.

7.0 Interim Emission Limits and Operating Practices

When the new maintenance plan is issued and made effective, the existing SIP Sections IX.H.1-4 will be repealed and replaced. On a federal level, the currently approved 1991 PM10 State Implementation Plan will be superseded with the newest version. As many of the requirements and emission limits in IX.H.1 and IX.H.2 for the refineries have implementation dates of January

1, 2018 or January 1, 2019, an "implementation gap" could have potentially existed between the effective date of the SIP and those future compliance dates.

In order to address this concern, new Subsection IX.H.4, titled Interim Emission Limits and Operating Practices has been established to serve as a bridge between these two periods. For all other point sources listed in IX.H.2 and IX.H.3 the limits apply upon approval by the Utah Air Quality Board of the PM_{10} Maintenance Plan.

There are two main sections of IX.H.4: a set of general requirements that applies to all petroleum refineries in or affecting any PM10 nonattainment/maintenance area, and then a set of specific requirements for each of the four listed refineries in IX.H.2 (BWO, Chevron, Holly and Tesoro). Both the general and specific requirements of IX.H.4 are designed to be used in conjunction with all of the requirements of IX.H.1. As these limits and operating practices are to serve only during the brief period between SIP issuance and January 1, 2019, only a bare minimum of requirements were retained. All requirements are specifically pulled from each source's latest AO, such that the source will continue to remain in compliance; however, each requirement also matches the 2005 State-only SIP. As the control technology for the sources listed in this subsection is installed and operational, the terms and conditions listed in IX.H.1 and IX.H.2 becomes applicable and those limits then replace the limits in this subsection.

For BWO the following conditions and limitations apply during the interim period:

A. Refinery General – retention of the 9.8 kg of SO2 per 1,000 kg of coke burn-off from any Catalytic Cracking unit limit.
B. Combined emissions of filterable PM10 from all external combustion process equipment shall not exceed the following:
    a. 0.377 tons per day, between October 1 and March 31;
    b. 0.407 tons per day, between April 1 and September 30
C. Combined emissions of sulfur dioxide from all external combustion process equipment shall not exceed the following:
    a. 2.764 tons/day, between October 1 and March 31;
    b. 3.639 tons/day, between April 1 and September 30
D. Combined emissions of NOx from all external combustion process equipment shall not exceed the following:
    a. 1.027 tons per day, between October 1 and March 31;
    b. 1.145 tons per day, between April 1 and September 30

Each limit has an associated compliance demonstration method and averaging period.

8.0 Implementation Schedule

The daily (24-hour) emission Caps are effective as of January 1, 2019. This schedule is dictated by the original RACT requirements established under the $PM_{2.5}$ SIP of 2014 (IX.H.11-13). In order to allow for construction, installation, shakedown and initial testing of the new equipment, this January 1, 2019 date was selected. Demonstration of attainment under the new PM_{10} maintenance plan is also set as January 1, 2019.

The provisions of IX.H.1.a-f (the General Requirements) are effective immediately upon implementation of the new maintenance plan. Those listed in IX.H.1.g (Refineries) have variable implementation dates depending on the specific provision. Some take effect immediately, while others take effect on January 1, 2018 or on January 1, 2019. Again, these dates exactly match

those listed in the $PM_{2.5}$ section of the SIP (IX.H.11).

In order to address the possibility of an "implementation gap" from occurring, interim emission limits and operating practices have been established. These interim requirements are found in Subsection IX.H.4 of the new maintenance plan. For complete details on these requirements, please see Item 7.0 above.

9.0 References

- Will be provided upon completion of the TSD

Evaluation Report – Big West Oil Refinery

UTAH PM_{10} SIP/MAINTENANCE PLAN

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report: Bountiful City Light and Power

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM10 SIP/MAINTENANCE PLAN EVALUATION REPORT
Bountiful City Light and Power

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the Utah Implementation Plan (SIP); to address the Salt Lake County PM_{10} Nonattainment Area (SLCNA). This document specifically serves as an evaluation of the Bountiful City Light and Power operated power plant.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Sections IX.H.1-4 of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report.
- When referencing the original SIP with an effective date of August 8, 1994 the qualifier $^{\{OS\}}$ will follow any citation from that document.
- In reference to the updated Utah County SIP with an effective date of January 22, 2003 the qualifier $^{\{UC\}}$ will follow any citation from that document.
- When referencing any new Maintenance Plan/SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Bountiful City Light and Power – Power Plant
Address: 253 South 200 West, Bountiful, Utah, Davis County
Owner/Operator: Bountiful City Light and Power
UTM coordinates: 425,450 East 4,526,400 North Zone 12

1.2 Facility Process Summary

Bountiful City Light and Power (BCLP) operates a power plant consisting of two 13.5 MW natural gas-fired turbines, one 5.3 MW natural gas-fired turbine, and one 250 kW natural gas-fired emergency generator. There are also three small cooling towers. The power plant is operated as a peaking and supplemental power plant to provide electrical power to municipal power customers in and around the City of Bountiful. The plant is defined as a Title V major source located in Davis County, and was included in the 1994 SIP as affecting the SLCNA.

An Approval Order (AO) for the two 13.5 MW turbines was issued in September 2010, the AO for the emergency generator was issued March 2013. Aside from the emergency generator, operation of the plant is dependent on local demand and cost of utility power.

1.3 Facility Criteria Air Pollutant Emissions Sources

As previously discussed the facility contains the following emission sources:
5.3 MW $LoNO_x$ natural gas-fired turbine (GT #1)
13.5 MW $LoNO_x$ natural gas-fired turbine (GT #2)
13.5 MW $LoNO_x$ natural gas-fired turbine (GT #3)
250 kW natural gas-fired emergency generator (Em Gen)
Cooling Tower #1
Cooling Tower #2
Cooling Tower #3

1.4 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, BCLP's baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	0.0894
SO_2	0.0155
NO_x	0.3183

The current PTE values for BCLP, as established by the most recent AO issued to the source (DAQE-AN101200003-13) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	36.9
SO_2	6.7
NO_x	160.0

However, please see Table 3 below for further details on BCLP's true PTE value.

2.0 Modeled Emission Values

Unlike the base year inventory, which used only the 2011 actual emissions for each source to set the baseline for modeling, a modified version of the PTE values was used for the modeled attainment demonstration. Beginning with the PTE values listed in Table 2 (from the most recent approval order issued to BCLP in 2013), these emissions were then "trued-up" by including the

expected effects from implementation of RACT from the $PM_{2.5}$ SIP. This true-up yields a 2019 Projected Emission Value for each of the pollutants of concern. Where necessary, these values were further corrected for condensable particulates using simple correction factors based on fuel consumed or process type.

Where gaseous fuels such as natural gas were combusted, filterable-only emissions were converted to a filterable+condensable emission value by multiplying the filterable rate by 4. For natural gas, AP-42 lists the various emission factors as:

Filterable PM: 1.9 lb/106 scf
Condensable PM: 5.7 lb/106 scf
Total PM: 7.6 lb/106 scf

In other words, the total PM is almost exactly four times the filterable emission value. Liquid fuels, such as diesel fuel #2, were also converted using the latest AP-42 emission factors. Processes such as cooling towers, which emit largely filterable-only emissions, were not adjusted. Other processes were adjusted, as needed, on a case-by-case basis using the best data available – primarily the latest stack test information.

For BCLP, the true-up and correction results in the following modeled emission values – summarized in Table 3.

Table 3: Modeled Emission Values

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	36.9
SO_2	6.7
NO_x	100.0

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the December 3, 2014 $PM_{2.5}$ Section of the SIP (IX.H.11-13). This section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM_{10} SIP sources – including the BCLP power plant. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11-13 – which comprise the $PM_{2.5}$ sections of the SIP, and include this additional RACT application. All requirements from the original PM_{10} SIP that have not been superseded or replaced, and which are still necessary, will also be retained. By necessary, meaning: significant from the standpoint of PM_{10} control, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

BCLP is a previously listed SIP source. In the original PM_{10} SIP, BCLP was listed in Subsection IX.H.2.b.D$^{\{OS\}}$ as Bountiful City Light and Power. As a listed source there were several requirements and conditions that applied to the facility.

In addition, BCLP is also a listed source in the $PM_{2.5}$ Section of the SIP (see SIP Section IX.H.12.c). As was discussed above in Item 2.0, all limits in this maintenance plan are based on the limits in the December 3, 2014 $PM_{2.5}$ SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.c. Therefore, a comparison between the

original SIP requirements, and those found in this new maintenance plan can be found below:

3.1 Original SIP General Requirements

IX.H.2.a General Requirements{OS}

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a{OS} applied to the listed sources found in Utah County, while those found at IX.H.2.a{OS} applied to the listed sources found in Salt Lake and Davis County. As the BCLP power plant was (and is) located in Davis County, only the general requirements of IX.H.2.a{OS} applied.

2.a.A. Stack Testing{OS} – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which serves the same purpose.

2.a.B. Visible Emissions{OS} – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.C. Visible Emissions (cont.){OS} – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.D. Annual Emission Limitations{OS} – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists, and no source-specific annual SIP Caps appear in either IX.H.2 or IX.H.3 of the new maintenance plan.

2.a.E. Recordkeeping Requirements{OS} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders{OS} – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance{OS} – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program, under R307-401-4(1).

2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program, under R307-401-3(1)(b).

2a.I. Unpaved Operational Areas{OS} – established rules for treating fugitive dust with water sprays or chemical dust suppression. This requirement has been superseded by the fugitive dust rules of R307-205 and R307-1-4.5, or the most recent federally approved fugitive dust rule.

2.a.J. Actual Emissions{OS} – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsections IX.H.1-4 of the SIP. This requirement is outdated and obsolete.

2.a.K. Test if Directed{OS} – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions{OS} – established that the definitions contained in R307 apply to subsection IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.M. Petroleum Refineries{OS} – This is a fairly lengthy subsection pertaining only to the petroleum refineries. This subsection has its own sub-subsections, owing to the overall length and complexity. This subsection has been replaced generally by the new maintenance plan requirements found at IX.H.1.g; however, as this source is not a petroleum refinery, this subsection does not apply.

2.a.N. Specific Fuel Requirements for Coal and/or Oil{OS} – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded by the individual source requirements found in IX.H.2 and IX.H.3 (see specifically the sources Kennecott and BYU). This requirement is now largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources have the ability to burn any other fuel oils.

3.3 Original SIP Source Specific Requirements

Individual source requirements:

2.b.D.1.{OS} This subsection was a listing of the equipment at the power plant – this subsection has been superseded and is irrelevant. A simple listing of equipment does not constitute an emission limitation, does not impose any restriction on daily emissions, and rapidly becomes out of date as well as impossible to enforce. The original listing found in this subsection does not match the current equipment installed and operating at the plant and would represent a significant step backwards in emission control and power generating technology.

2.b.D.2.{OS} Emissions limitations on engine #8. This subsection was unusual for the original SIP in that it not only included an emission limit on NO_x (a PM_{10} precursor pollutant), but it also included emission limits on CO and VOC – which are not PM_{10} precursors. This subsection is no longer relevant as engine #8 has been removed from the site and is no longer in service. It has been superseded by new maintenance plan subsection IX.H.2.b.i – which establishes limits on NO_x emissions from the remaining equipment at the site.

2.b.D.3.{OS} Stack testing on engine #8. As with the previous condition, this subsection has been superseded and is no longer relevant. Engine #8 has been removed, so any requirement to conduct emissions testing would be superfluous. It has been replaced with new maintenance plan subsection IX.H.2.b.ii – which outlines the compliance methodology to be used in association

with the limits established in IX.H.2.b.i.

2.b.D.4.{OS} Stack testing on engines #1-7. Another unusual condition, this subsection established a stack testing methodology on engines 1-7 to demonstrate compliance with NO_x and CO limits that did not actually appear in the original SIP. It is not known whether these limits were simply left out of the original SIP conditions by accident, or whether this condition was supposed to set these limits through an initial stack test.

This condition also limited the fuel types available for use in all "furnaces, ovens and boilers" and that fuel oil could only be used as a pilot fuel or during natural gas curtailments. As the source never had any furnaces, ovens or boilers, this condition was badly worded. The obvious intention was to limit the dual fuel engines to only operating on natural gas for steady-state operation, with fuel oil as a startup fuel except during curtailment periods.

Finally, a requirement to install and operate a CEM if total emissions of NO_x were to ever exceed 200 tpy within a given 12-month consecutive period.

However, this condition is also no longer relevant as the equipment in question (engines 1-7) has been removed and is no longer in service. The condition has not been directly superseded, although; condition IX.H.2.b.ii of the new maintenance plan is the most direct comparison. The new turbines installed at the facility are natural gas-fired only, and cannot operate on any other fuel, so no allowance for fuel switching needs to be preserved. The requirement to install and operate a CEM has been removed, as total facility emissions of NO_x on an annual basis are estimated at only 100 tpy with the removal of all the original dual-fuel engines.

2.b.D.5.{OS} Total power generation restriction. This condition limited the total power generation from the facility. As the emissions from the original eight engines were limited only by total operation – hence total power generation, this original SIP limitation kept total emissions in check. However, this requirement is no longer necessary or valid. Total emissions from the facility are not based on the operation of the dual fueled engines as none of the original 8 engines remains in operation at the facility. Instead, the facility now operates three natural gas fired combustion turbines. At full load, the facility's PTE has decreased from 250 tpy to a maximum of 160 tpy of NO_x (the primary pollutant of concern). Limiting total power production would unnecessarily restrict BCLP's ability to inexpensively produce power without any net positive benefit to the environment. Therefore, this requirement has been dropped.

2.b.D.6.{OS} Operating parameters on engine #8. This condition established several parameters for purposes of demonstrating compliance in the operating of engine #8. As with the other conditions which formerly applied to engine #8, this condition is also no longer relevant and has been dropped. The removal of engine #8 from the facility renders the usefulness of this condition highly questionable. Although the original condition has not been directly superseded, condition IX.H.2.b.iii of the new maintenance plan is similar. This new condition details startup and shutdown procedures to minimize emissions during those two periods.

Table 4 shows a comparison of the original SIP emission values, to the new maintenance plan expected emission rates. The original SIP established annual values for each of the three pollutants; however, the new maintenance plan includes only direct emission limits on NO_x. This is because the source has removed all of the original dual-fueled IC engines and replaced them with three natural gas-fired combustion turbines. As emissions of direct PM_{10} and SO_2 are so low from this type of equipment, only the emissions of NO_x warrant specific limitations under Section IX.H.2. Therefore, the emissions for both PM_{10} and SO_2 are estimates based on the PTE

values from BLCP's most recent permit. Emissions of NO_x include only the remaining emitting units still installed at the site; namely: the three combustion turbines, the single emergency generator, and three cooling towers.

Also worth noting is the single NO_x daily value. This value is also a derived value, as the limits from the new maintenance plan are expressed as (lbs/hr) and (grams/kW-hr). Therefore, a maximum potential emission was taken based on the highest output of the turbine and the number of hours of operation (24-hours in this case). For comparison purposes, the estimate of daily NO_x emissions from the original SIP was determined by simply dividing the annual value by 365 days. This provides a value which can be used to compare with the new maintenance plan, but serves no other useful purpose.

Table 4: Comparison Table – Old SIP Emissions vs New Maintenance Plan Emissions

All values in tons	**SO_2 Original**	**SO_2 New**	**NO_x Original**	**NO_x New**	**PM_{10} Original**	**PM_{10} New**
Annual	5.97	6.7*	250.0	100.0*	1.06$	36.9&
Daily (24-hr)	-	-	0.685#	0.264*	-	-

* includes only emissions from turbines GT #1, #2, #3 and the emergency generator
$ filterable emissions only
& includes condensable emissions and particulate emissions from three cooling towers
# estimate of daily emissions provided for comparison purposes only

Direct comparison between the two PM10 values is somewhat problematic. The original SIP's emission value of 1.06 tpy included only filterable emissions, while the new maintenance plan takes condensable emissions into account. As was discussed in Item 2.0 above, this results in an emission value four times as large as if only filterable emissions are considered. To make a comparison only between filterable emissions, one must first subtract out the contribution from the cooling towers (emission sources which do not contribute condensable particulate). The cooling towers account for approximately 3.3 tpy of direct PM10 emissions. Dividing the remaining 33.6 tons by 4 yields the approximate contribution from the three natural gas turbines and emergency generator. If a comparison of only filterable emissions is made, the value for the new maintenance plan would then be listed as 11.7 tpy (filterable only).

However, there is a second problem to consider. When reviewing the emissions from the original SIP, it became apparent that the PM10 potential emission value was very likely in error – based on the potential NOx emissions, comparison with similar equipment installed at other operating plants (Payson City Power, Provo City Power, Springville City Power), comparison with AP-42 emission factors, and the source's own stack testing. Although the dual-fuel engines have since been removed, the PM10 emission factor for each of the engines was 0.044 g/kW-hr; while the emission factor for NOx for the engine with the highest number of hours used was 7.44 g/kW-hr – a ratio of 0.006. Simply multiplying the original SIP's estimate of annual NOx emissions by this ratio would have yielded a PM10 value of 1.5 tpy. And with an average emission factor for NOx closer to 5.0 g/kW-hr, that ratio increases to 0.009 – for an estimated annual PM10 value of 2.2 tpy. This error in estimating PM10 emissions has prevented UDAQ from issuing a Part 70 Operating Permit for BCLP as the extremely low estimate of emissions prevented BCLP from operating the dual-fuel engines at their capacity, and eventually led the source to replace the engines with new natural gas-fired turbines.

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference. As specifically stated in subsection IX.H.1.a below, these general requirements apply to all sources subsequently listed in either IX.H.2 (Salt Lake County) or IX.H.3 (Utah County), and are in addition to (and in most cases supplemental to) any source-specific requirements found within those two subsections.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule R307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation. All conditions in these subsections are strictly in accordance with EPA approved methods and guidelines.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow in the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – BCLP Specific Requirements

The BCLP specific conditions in Section IX.H.2 address those limitations and requirements that apply only to the BCLP Power Plant in particular.

IX.H.2.b.i This condition lists the specific NO_x limitations applicable to the three combustion turbines operating at BCLP. For combustion turbine #1 (designated GT #1), that limit is expressed as 0.6 g NO_x per kW-hr. For turbines #2 and #3 (GT #2 and GT #3) the limits are 7.5 lb/hr.

The limits are differently expressed because the three turbines were installed at different times

and operated differently by the source. The two larger turbines (GT #2 and #3) are used in more of a base load capacity as high demand warrants, while the smaller turbine can be cycled on and off to deal with more rapid fluctuations in local demand.

IX.H.2.b.ii This condition establishes the stack testing frequency requirement to demonstrate compliance with the limits in IX.H.2.b.i. Each turbine shall be tested at least once per year.

As BCLP's total emissions of NO_x only reach 100 tons per year, annual stack testing is more than sufficient to demonstrate compliance. To include a requirement for installation of CEMs, such as is required on other similarly sized power plants would be excessive. That requirement includes language which activates the installation and operation of a CEM once emissions of NO_x reach a specific threshold. In this case, any reasonably selectable threshold (such as 100 tpy) is already equal to or greater than the total emissions of NO_x released by the source. In addition, this is the same testing frequency required by the original SIP.

IX.H.2.b.iii This condition outlines a turbine startup/shutdown emission minimization plan. The terms "startup" and "shutdown" are both defined, and the length of time each turbine can operate in either mode is outlined.

However, neither mode is given a separate emission limitation. The emission limits outlined in IX.H.2.b.i still apply at all times, including startup and shutdown.

5.1 Monitoring, Recordkeeping and Reporting

Monitoring for IX.H.2.b.i is specifically outlined in IX.H.2.b.ii. Stack testing for NO_x emissions is required on each turbine at a minimum of once each year. Stack testing will follow the procedures otherwise outlined in IX.H.1.e for all stack testing and reporting requirements. Recordkeeping is subject to the requirements of IX.H.1.c.

5.2 Discussion of Attainment Demonstration

Both in the original SIP and in the new maintenance plan, BCLP was primarily a source of NO_x emissions. While some direct PM_{10} and SO_2 emissions added to the overall contribution from BCLP, it remains a listed source because of NO_x. Total emissions of NO_x have dropped from 250 tons per year in the original SIP to an estimated 100 tons in the new maintenance plan. While direct PM_{10} emissions have increased slightly, this is due primarily to the contribution of condensable particulates, which were not included in the original SIP. Some direct PM_{10} is also provided from the new cooling towers. Emissions of SO_2 have remained roughly equal.

6.0 Implementation Schedule

For the most part, the requirements imposed on BCLP are effective immediately. While some provision was made for sources generally to implement the RACT requirements of the $PM_{2.5}$ SIP (and which were included as part of the modeled emission values for each source as discussed in that section above), the BCLP plant did not have any required RACT modifications. The source removed the last remaining dual-fuel engine (engine #8) in 2014, leaving only the three combustion turbines and an emergency "black start" generator at the site. The emission limits listed in IX.H.2.j can be applied immediately. Similarly, the provisions of IX.H.1.a-f (the General Requirements) can also be applied immediately.

7.0 References

Evaluation Report – BCLP Power Plant

UTAH PM_{10} SIP

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report: Central Valley Water Reclamation

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT

Central Valley Water Reclamation

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the Utah Maintenance Plan (the Plan); to address the Salt Lake County PM_{10} Nonattainment Area. This document specifically serves as an evaluation of Central Valley Water Reclamation.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Section IX.H of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report.
- When referencing the original SIP with an effective date of August 8, 1994 the qualifier $^{\{OS\}}$ will follow any citation from that document.
- When referencing any new Maintenance Plan/SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

2.0 Facility Identification

Name: Central Valley Water Reclamation Facility
Address: 800 West Central Valley Road, Salt Lake City, Utah, Salt Lake County
Owner/Operator: Central Valley Water Reclamation
UTM coordinates: 422,600 Easting 4,506,500 Northing Zone 12

3.0 Facility Process Summary

Central Valley Water Reclamation Facility (CVWRF) is a municipal wastewater treatment facility located in Salt Lake City. The primary SIC Code for the facility is 4952-Sewage Systems.

The facility operates under Utah DAQ AO DAQE-AN0104140011-09, dated August 18, 2009. The facility is subject to 40 CFR 60 Subparts A-General Provisions and Subpart IIII regulations – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. Additionally, Title V of the 1990 Clean Air Act applies to this facility. CVWRF is a major source for NO_x and CO.

4.0 Facility Criteria Air Pollutant Emissions Sources

The facility consists of the following emission sources

- Five (5) Waukesha Engine Generators (3-1340 kW and 2-1150 kW)
- One (1) Water-wash Paint Spray Booth
- Four (4) Emergency generators (1186 hp, 2-896 hp, 349 hp)
- Digesters
- Biological Process
- Two (2) Digester Flares
- Composting

5.0 Facility 2011 Baseline Actual Emissions and Current PTE

CVWRF actual emissions are lower than its Potential to Emit for all pollutants.

Table 1: Comparison of Actual and Potential Emissions

Pollutant	Actual Emissions (Tons/Year)[1]	Potential to Emit (Tons/Year)[2]
PM_{10}	1.75	2.23
SO_2	0.58	5.09
NO_x	25.79	150.00

[1] CVWRF's 2011 actual emissions
[2] PTE's for CVWRF's AO issued DAQE-AN0104140011-09, dated August 18, 2009

6.0 Projected Emissions for 2019

The 2019 projected emissions were estimated from the actual emissions inventory submitted for 2011 and emissions from composting, emergency generator engines, and two flares.

Table 3: 2019 Projected Emission Values or Modeled Emission Values

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	1.83
SO_2	0.61
NO_x	29.28

7.0 Comparison of Requirements – Original SIP and New Maintenance Plan

CVWRF is a previously listed SIP source. In the original PM_{10} SIP document for Salt Lake County {OS}. Requirements for CVWRF are found in IX.2.2.E{OS}.

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent PM2.5 Section of the SIP. This section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM_{10} SIP sources. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11, IX.H.12 and IX.H.13 – which comprise the PM2.5 sections of the SIP, and include this additional RACT application. All requirements from the original PM_{10} SIP that have not been superseded or replaced, and which are still necessary, will also be retained. By necessary, meaning: needed in the demonstration of attainment of the 24-hour standard, or in demonstrating that no backsliding in the application of RACT has taken place.

All limits in this maintenance plan are based on the limits in the PM2.5 SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.k. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below.

7.1 SIP General Requirements

The following is a list of the requirements from the Salt Lake County {OS} SIP and a discussion of each of the requirement including current relevance and expected changes.

IX.H.2.a General Requirements{OS}

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a{OS} applied to the listed sources found in Utah County, while those found at IX.H.2.a{OS} applied to the listed sources found in Salt Lake and Davis County.

2.a.A. Stack Testing{OS} – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which incorporates equivalent language.

2.a.B. Visible Emissions{OS} – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.C. Visible Emissions (cont.){OS} – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which serves incorporates equivalent language.

2.a.D. Annual Emission Limitations{OS} – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists, and no source-specific annual SIP Caps appear in either IX.H.2 or IX.H.3 of the new maintenance plan.

2.a.E. Recordkeeping Requirements{OS} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders (AOs){OS} – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance{OS} – established that all facilities need to be adequately and properly maintained. The requirement is not needed, as this is inherent in the NSR permitting program, under R307-401-4(1).

2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. The requirement is not needed, as this is inherent in the NSR permitting program, under R307-401-3(1)(b).

2a.I. Unpaved Operational Areas{OS} – established rules for treating fugitive dust with water sprays or chemical dust suppression. This requirement has been superseded by the nonattainment area fugitive dust control requirements of R307-309.

2.a.J. Actual Emissions{OS} – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsection IX.H of the SIP.

2.a.K. Test if Directed{OS} – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions{OS} – established that the definitions contained in R307 apply to Section IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.N. Specific Fuel Requirements for Coal and/or Oil{OS} – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded by the individual source requirements found in IX.H.2 and IX.H.3 (see specifically the sources Kennecott and BYU). This requirement is now largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources have the ability to burn any other fuel oils

7.2 SIP Source Specific Requirements

The requirements and limits specific to CVWRF were extensive and will not be added to this document. Rather a summary of the requirements and highlights of the requirements will be discussed.

The equipment list included one (1) 1135 kW generator engine set and four (4) 625 kW generator engine set. The new 1135 kW generator engine set to be installed was to achieve a reduction in NO_x emissions with a clean burn configuration. NO_x and CO emissions rates and concentrations were given for the 1135 kW generator engine set.

In addition to the equipment list and emission rates, compliance was determined by submitting a quarterly report with the measured oxygen, CO an NO_x concentrations in the exhaust stream prior to passing and after passing through the catalyst. The concentrations were measured with a portable meter on a monthly basis.

The Original SIP{OS} limited CVWRF to the use of natural gas or digester gas to fuel the engines. Finally, the engine use was limited to 13.35×10^3 MW-hr/yr for the uncontrolled engines and 5.475 MW-hr/yr for the engine burning natural gas with the catalytic converter.

The NO_x emissions since the 1994 SIP have decreased from 203.7 to 150 tons per year with the removal of the one (1) 1135 kW and four (4) 625 kW generator engine sets and the addition of three (3) 1340 kW and two (2) 1150 kW generator engines sets. The entire SIP for CVWRF needs to be updated to the equipment that is currently installed.

7.3 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference. As specifically stated in subsection IX.H.1.a below, these general requirements apply to all sources subsequently listed in either IX.H.2 (Salt Lake County) or IX.H.3 (Utah County), and are in addition to (and in most cases supplemental to) any source-specific requirements found within those two subsections.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test

Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

7.4 New Maintenance Plan – Central Valley Specific Requirements

IX.H.2. c Central Valley Water Reclamation Facility: Wastewater Treatment Plant

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

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

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

A. The NO_x emission factor for each engine shall be derived from the most recent stack test. Stack tests shall be performed in accordance with IX.H.1.e. Each engine shall be tested at least every three years from the previous test.

B. NO_x emissions shall be calculated on a daily basis.

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

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

Discussion – The SIP has been updated with new emission limits to correspond to equipment with lower emission rates. Central Valley Water reclamation is limited to 0.648 tons per day of NOx with stack testing every three years to verify emission factors. Stack testing has already been completed and emission factors determined from this sampling will be used in place of an initial stack test. The condition also includes the definition of a day as being from midnight until the following midnight.

8.0 Monitoring, Recordkeeping and Reporting

Compliance monitoring of the limits is given in IX.H.2.e.i.c. CVWRF monitors its compliance with daily limits through examination of power generation records and emission factors measured by stack testing. Stack testing occurs at least every three years per engine.

All common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

9.0 Discussion of Attainment Demonstration

The general requirements act as a framework that the other requirements can build. Second, they demonstrate a prevention of backsliding. Through the use of general requirements that are either the same as or functionally equivalent to those in the 1994 Original SIP, backsliding has been prevented. Finally, when a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument could be made in that regard, the requirement was simply removed.

Source specific limits are equivalent to or more restrictive than the requirements from the 1994 Original SIP. NO_x emissions have decreased since the 1994 SIP and more efficient engines have been installed. Further, a daily emission cap has been set for CVWRF.

10.0 Implementation Schedule

The requirements imposed on the CVWRF are effective immediately. It did not have any required RACT modifications to undertake from the PM2.5 SIP RACT requirements. Therefore, the daily emission limits in IX.H.3.g can be applied immediately. Similarly, the general requirements, IX.H.1.a-f, can also be applied immediately.

11.0 Daily Emissions

Table 4: Yearly Emission Estimates and Potential Daily Emissions

All values in tons	Original SIP NO_x	NO_x
Annual Emissions	203.70[OS}]	150.00[**]
Daily (24-hr)	0.56[*]	0.648[***]

* Assumes NO_x annual emission estimates divided by 365 days per year.
[**]PTE from AO DAQE-AN0104140011-09, dated August 18, 2009
[***]PM_{10} SIP Limit

12.0 References

PM_{10} SIP/Maintenance Plan Evaluation Report:
Central Valley Water Reclamation

Supporting Information

PM10 SIP/Maintenance Plan Evaluation Report: Chevron Products Company

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM10 SIP/MAINTENANCE PLAN EVALUATION REPORT
Chevron Refinery

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the Utah Implementation Plan (SIP); to address the Salt Lake County PM10 Nonattainment Area (SLCNA). This document specifically serves as an evaluation of the Chevron Refinery.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Sections IX.H.1-4 of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report. However, see Section 7.0 of this document for some clarification.
- When referencing the original SIP with an effective date of August 8, 1994 the qualifier $^{\{OS\}}$ will follow any citation from that document.
- In reference to the updated Utah County SIP with an effective date of January 22, 2003 the qualifier $^{\{UC\}}$ will follow any citation from that document.
- When referencing any new Maintenance Plan/SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Chevron Salt Lake Refinery (Chevron)
Address: 2351 N 1100 W, Salt Lake City, Utah, Davis County
Owner/Operator: Chevron Products Company
UTM coordinates: 4,519,770 m Northing, 422,270 m Easting, Zone 12

1.2 Facility Process Summary

The Chevron Refinery is a petroleum refinery with a nominal capacity of approximately 50,000 barrels per day of crude oil. The source consists of a FCCU, delayed coking unit, catalytic reforming unit, hydrotreating units and a sulfur recovery unit. The source also has the usual assorted heaters, boilers, cooling towers, storage tanks, flares, and similar fugitive emissions. The refinery also operates with a flare gas recovery system on its hydrocarbon flares.

1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of the main emitting units from the Chevron Refinery:

Boiler #1
Boiler #2
Boiler #4
Boiler #5 (Low-NOx)
Boiler #6 (Low-NOx)
Cooling Tower #1
Cooling Tower #2
Cooling Tower #3
Cooling Tower #4 (Grandfathered)
Crude Unit Furnace #1 (Low-NOx)
Crude Unit Furnace #2 (Low-NOx)
FCC Furnace #1
FCC Furnace #2
HDN Furnace #1
HDN Furnace #2
Reformer Furnace F-1
Reformer Furnace F-2
Reformer Furnace F-3
Alkylation Furnace (Low-NOx)
Coker Furnace
HDS Furnace #1 (Low-NOx)
HDS Furnace #2 (Low-NOx)
VGO Furnace #1 (Low-NOx)
VGO Furnace #2 (Low-NOx)
SRU/TGTU/TGI #1 (SRU and Tail Gas Incinerator #1)
SRU/TGTU/TGI #2 (SRU and Tail Gas Incinerator #2)
Amine Unit #1
Amine Unit #2
FCCU and Catalyst Regenerator
Flameless Thermal Oxidizer
Coker Flare (Flare #1)
FCCU Flare (Flare #2)
Alkylation Flare (Flare #3)
Diesel-powered back-up equipment:
1 Emergency air compressor
6 Emergency generators
1 Emergency cooling water pump
2 HF Mitigation pumps
Reformer Compressor Drivers (natural gas-fired)
Tank Farm

Loading/Unloading
Fugitives
Wastewater Treatment Plant

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at the refinery, rather it is a listing of all significant emission units or emission unit groups (such as the tank farm).

1.4 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, Chevron's baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	47.30
SO_2	24.31
NO_x	319.57

The current PTE values for Chevron, as established by the most recent AO issued to the source (DAQE-AN101190092-15) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	85.0
SO_2	383.3
NO_x	766.5

2.0 Modeled Emission Values

Unlike the base year inventory, which used only the 2011 actual emissions for each source to set the baseline for modeling, a modified version of the PTE values was used for the modeled attainment demonstration. Beginning with the PTE values listed in Table 2 (from the most recent approval order issued to BWO in 2015), these emissions were then "trued-up" by including the expected effects from implementation of RACT from the PM2.5 SIP. This true-up yields a 2019 Projected Emission Value for each of the pollutants of concern. Where necessary, these values were further corrected for condensable particulates using simple correction factors based on fuel consumed or process type.

Where gaseous fuels, such as natural gas or refinery fuel gas, were combusted, filterable-only emissions were converted to a filterable+condensable emission value by multiplying the filterable rate by 4 (see explanation in section 3.3 of this document under the subheading of "Basis for the PM10 Emission Limitations"). Liquid fuels, such as diesel fuel #2, were converted using the latest AP-42 emission factors. Processes such as cooling towers, which emit largely filterable-only emissions, were not adjusted. Other processes were adjusted, as needed, on a case-by-case basis using the best data available – primarily the latest stack test information.

For the Chevron Refinery, this yielded the following modeled emission values – summarized in Table 3.

Table 3: Modeled Emission Values

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	258.1
SO_2	383.3
NO_x	766.5

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the December 3, 2014 PM2.5 Section of the SIP (IX.H.11-13). This section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM10 SIP sources – including the refineries in general, and the Chevron Refinery in specific. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11-13 – which comprise the PM2.5 sections of the SIP, and include this additional RACT application. All requirements from the original PM10 SIP that have not been superseded or replaced, and which are still necessary, will also be retained. By necessary, meaning: significant from the standpoint of PM10 control, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

Chevron is a previously listed SIP source. In the original PM_{10} SIP, Chevron was listed in Subsection IX.H.2.b.G$^{\{OS\}}$ as Chevron U.S.A. Inc.. As a listed source there were several requirements and conditions that applied to the facility.

In addition, Chevron is also a listed source in the PM2.5 Section of the SIP (see SIP Section IX.H.12.g). As was discussed above in Item 2.0, all limits in this maintenance plan are based on the limits in the December 3, 2014 PM2.5 SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.g. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below:

3.1 Original SIP General Requirements

IX.H.2.a General Requirements$^{\{OS\}}$

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a$^{\{OS\}}$ applied to the listed sources found in Utah County, while those found at IX.H.2.a$^{\{OS\}}$ applied to the listed sources found in Salt Lake and Davis County. As the Chevron Refinery was (and is) located in Davis County, only the general requirements of IX.H.2.a$^{\{OS\}}$ applied. However, except for the additional requirements found under IX.H.2.a.M$^{\{OS\}}$ for petroleum refineries and the specific fuel requirements of IX.H.2.a.N$^{\{OS\}}$, the two subsections are essentially identical.

2.a.A. Stack Testing$^{\{OS\}}$ – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which serves the same purpose.

2.a.B. Visible Emissions$^{\{OS\}}$ – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by

SIP subsection IX.H.1.f which serves the same purpose.

2.a.C. Visible Emissions (cont.)$^{\{OS\}}$ – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.D. Annual Emission Limitations$^{\{OS\}}$ – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists, and no source-specific annual SIP Caps appear in either IX.H.2 or IX.H.3 of the new maintenance plan.

2.a.E. Recordkeeping Requirements$^{\{OS\}}$ – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders$^{\{OS\}}$ – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance$^{\{OS\}}$ – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program, under R307-401-4(1).

2.a.H. Future Modifications$^{\{OS\}}$ – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program, under R307-401-3(1)(b).

2a.I. Unpaved Operational Areas$^{\{OS\}}$ – established rules for treating fugitive dust with water sprays or chemical dust suppression. This requirement has been superseded by the fugitive dust rules of R307-205 and R307-1-4.5, or the most recent federally approved fugitive dust rule.

2.a.J. Actual Emissions$^{\{OS\}}$ – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsections IX.H.1-4 of the SIP. This requirement is outdated and obsolete.

2.a.K. Test if Directed$^{\{OS\}}$ – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions$^{\{OS\}}$ – established that the definitions contained in R307 apply to subsection IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.N. Specific Fuel Requirements for Coal and/or Oil$^{\{OS\}}$ – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded by the individual source requirements found in IX.H.2 and IX.H.3 (see specifically the sources Kennecott and BYU). This requirement is now largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with

lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources have the ability to burn any other fuel oils.

3.2 Original SIP Petroleum Refinery Requirements

2.a.M. Petroleum Refineries{OS} – This is a fairly lengthy subsection pertaining only to the petroleum refineries. This subsection has its own sub-subsections, owing to the overall length and complexity.

2.a.M.A. Sulfur Recovery Units (SRUs){OS} – established the requirement for 95% efficient SRUs, no burning of liquid fuel oil except during natural gas curtailments, use of low-SO_x catalyst to attain a 9.8 kg SO_2/1000 kg coke burnoff in FCC units, amine and sour water overhead streams shall also be processed in the SRU. These conditions currently remain in effect. The SO_2 limit is largely irrelevant as the limitation in SIP subsection IX.H.1.g.i.A.I is based on 40 CFR 60, Subpart Ja, and is more stringent. The other three requirements: 95% efficient SRUs, no burning of liquid fuel oil, & amine and sour water overhead streams being processed in the SRU, shall be retained. These three conditions are found at SIP subsections IX.H.1.g.iii, IX.H.1.g.iv, and IX.H.1.g.iii, respectively.

2.a.M.B. Routine Turnaround Periods{OS} – established exclusion periods when routine turnarounds of the SRUs could be performed, and the procedure for scheduling one of these periods. These conditions are no longer required. Each of the refineries has agreed to incorporate alterative language which supersedes these requirements. In Chevron's specific case, the refinery has opted to simply include SRU turnaround emissions within the existing 24-hour emission Caps – including all flaring and additional SO_2. As Chevron operates dual SRUs, each of which is capable of treating all fuel gas produced by the refinery during normal operations, a turnaround at one SRU system can be accommodated without excess emissions or increased flaring.

2.a.M.C.1. Compliance Demonstration part 1{OS} – established that SRU turnaround emissions and flaring emissions are not included in either the daily (24-hour) or annual compliance demonstrations. As with 2.a.M.B{OS} above, this requirement is no longer required. Each refinery has agreed to alternative language regarding SRU turnarounds (see the discussion on 2.a.M.B{OS} above). All flaring emissions have been included in the 24-hour emission Caps for each listed refinery.

2.a.M.C.2. Compliance Demonstration part 2{OS} – established how the daily (24-hr) emissions limits (Caps) would be determined, including recordkeeping and reporting requirements. This subsection has since been superseded by the individual source's SIP subsection (for Chevron, this would be Section IX.H.2.d) which establishes the 24-hour emission limits, and the monitoring, recordkeeping and reporting requirements associated with those limits.

2.a.M.C.3. Compliance Demonstration part 3{OS} – established a methodology for how emission limits could be modified/adjusted as necessary. This subsection is no longer required, as this procedure is no longer followed.

2.a.M.C.4. Compliance Demonstration part 4{OS} – also established that annual emissions for refineries followed a process essentially identical to the rolling 12-month process outlined above in 2.a.D{OS}. This subsection is no longer required as the specific requirement to track

annual emissions is no longer needed with the removal of the annual PM10 standard.

2.a.M.D. Process Flaring Emissions and Routine Turnaround Emissions{OS} – established that both sets of emissions were included in the modeled attainment demonstration. This subsection is no longer required, as a new attainment demonstration has been performed and both process flaring and routine turnaround emissions are handled differently in the new maintenance plan. As has been discussed above, process turnarounds (a term applied specifically to operation of the SRU) are now addressed by each individual refinery by incorporation of the turnaround within the daily Cap emission limits. Similarly, process flaring emissions are also included by default as the language which previously excluded these emissions has been removed.

3.3 Original SIP Source Specific Requirements

Individual source requirements:

2.b.G.1.{OS} This subsection was a listing of the equipment at the refinery – this subsection has been superseded and is irrelevant. A simple listing of equipment does not constitute an emission limitation, does not impose any restriction on daily emissions, and rapidly becomes out of date as well as impossible to enforce. The original listing found in this subsection does not match the current equipment installed and operating at the refinery and would represent a significant step backwards in emission control and refining technology.

2.b.G.2.{OS} Basis for SO_2 Emission Limitations – A) established the SO_2 daily and annual emission Caps. B) established the sources included in the SO_2 emissions Caps. Although [2.b.G.2.A){OS}] also included a "plant-wide" emission value, this value was based on the emissions from specific "Cap sources" which were listed in this subsection. C) established that the SO_2 emission Caps shall be determined by multiplying the amount of each type of fuel burned each day by specific emission factors listed in this subsection [2.b.G.2.C){OS}.]. The equations to be used, and the compliance methodology for various processes or fuel types was listed. This subsection also established SO2 monitoring and recordkeeping provisions. D) established individual point source limitations for specific sources, including the FCC CO boiler, SRU incinerator, and HCC plume boiler. E) established that stack testing would be performed as outlined in SIP subsections 2.b.G.5{OS}, 2.a.A{OS} and 2.a.M{OS}; specifically for the "non-capped" sources. F) established that the flares and the KOH regenerator lime bin baghouse were not included in the SO_2 Caps, and also not regulated for SO_2 emissions.

This subsection has since been superseded by the SIP subsection which establishes new plantwide SO_2 daily (24-hour) emission Caps (for Chevron, this would be Section IX.H.2.d.iii). These new SO_2 emission Caps cover all emission units at the refinery – including the flares – so no emission unit is excluded. The new SO_2 emission Caps are significantly lower than the original Caps (although the annual standard no longer exists, the comparison in Table 4 includes the expected annual emission values for each of the three pollutants as a convenient comparison with the original SIP emissions). The compliance methodology included in SIP subsection IX.H.2.d.iii also includes the calculation of amount of fuel burned multiplied by the emission factor for each fuel type – although these emission factors have been updated as needed. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below).

2.b.G.3.{OS} Basis for the NO_x Emission Limitations – Similar to the SO_2 limitations above: A) established the NO_x daily and annual emission Caps. B) established the sources included in the

NO_x emissions Caps. C) established that the NOx emission Caps shall be determined by multiplying the amount of each type of fuel burned each day by specific emission factors listed in this subsection [2.b.G.3.C)$^{\{OS\}}$.]. The equations to be used, and the compliance methodology for various processes or fuel types was listed. This subsection also established NOx monitoring and recordkeeping provisions. D) established individual point source limitations for specific sources, including the FCC CO boiler, SRU incinerator, and HCC plume boiler. E) established that stack testing would be performed as outlined in SIP subsections 2.b.G.5$^{\{OS\}}$, 2.a.A$^{\{OS\}}$ and 2.a.M$^{\{OS\}}$. F) established that the flares and the KOH regenerator lime bin baghouse were not included in the NO_x Caps, and also not regulated for NO_x emissions.

This subsection has since been superseded by SIP subsection IX.H.2.d.ii which establishes new plantwide NO_x daily (24-hour) emission Caps. As with the SO_2 emission Caps, these new NO_x emission Caps cover all emission units at the refinery – including the flares. The new NO_x emission Caps are also lower than the original Caps. As with SO2, annual values have been included for comparison purposes. Again, the compliance methodology included in SIP subsection IX.H.2.d.ii uses the amount of fuel burned multiplied by the emission factor for each fuel type. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below).

2.b.G.4.$^{\{OS\}}$ Basis for the PM10 Emission Limitations – Similar to both the SO2 and NOx limitations above: A) established the PM10 daily and annual emission Caps. B) established the sources included in the PM10 emissions Caps. C) established that the PM10 emission Caps shall be determined by multiplying the amount of each type of fuel burned each day by specific emission factors listed in this subsection [2.b.G.4.C)$^{\{OS\}}$.]. The equations to be used, and the compliance methodology for various processes or fuel types was listed. This subsection also established PM10 monitoring and recordkeeping provisions. D) established that the flares, and certain compressors were not included in the PM_{10} Caps, and also not regulated for PM_{10} emissions.

This subsection has since been superseded by SIP subsection IX.H.2.d.i which establishes new plantwide PM_{10} daily (24-hour) emission Caps. As with both the SO_2 and NO_x emission Caps, these new PM_{10} emission Caps cover all emission units at the refinery – including the flares. The annual values are also listed for ease of comparison. As before, the compliance methodology included in SIP subsection IX.H.2.d.i uses the amount of fuel burned multiplied by the emission factor for each fuel type. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below).

Table 4: Comparison Table – Old SIP Caps vs New SIP Caps

	SO_2 Original	**SO_2 New**	**NO_x Original**	**NO_x New**	**PM_{10} Original**	**PM_{10} New**
Annual	1,731.0	383.3	1,022.0	766.5	175.0$^{\$}$	258.1$^{\&}$
Annual (Cap Sources)	83.0	-	690.2	-	16.3$^{\$}$	-
Daily (24-hr)	5.104	1.05	3.249	2.1	0.479$^{\$}$	0.715$^{\&}$
Daily (Cap Sources)	0.254	-	2.341	-	0.044$^{\$}$	-

$^{\$}$ filterable emissions only

[&] includes condensable emissions

The new PM10 values for Chevron appear to be significantly larger than the original SIP emissions for the refinery. However, two factors need to be taken into account. The first is the difference between including only emission Cap sources in the emission total, and making the total "plant-wide" – as is now the case in this new maintenance plan. Chevron's equipment list is significantly different than it was when the original SIP was being developed. Chevron now operates a FCC unit, and no longer even has the HCC unit originally excluded from the emission Caps. However, the second, far more significant factor is the difference between filterable-only emissions and condensable emissions. The combustion of gaseous fuels like natural gas or refinery fuel gas have vastly different emission factors for filterable and for condensable particulate emissions. For natural gas, AP-42 lists the various emission factors as:

Filterable PM: 1.9 lb/10^6 scf
Condensable PM: 5.7 lb/10^6 scf
Total PM: 7.6 lb/10^6 scf

In recent stack tests, the emission factors for refinery fuel gas were equivalent to natural gas. In other words, the total PM is almost exactly four times the filterable emission value. When these two factors are taken together, the PM10 emissions at the Chevron refinery have actually decreased from the values listed in the original SIP.

2.b.G.5.{OS} Stack Testing Requirements – established which point sources were required to comply with specific emission limitations (established in preceding paragraphs), the test method to be used to verify compliance (including CEMs if applicable), and the frequency of testing and/or monitoring. Multiple sources had a frequency of "test if directed," which is no longer applicable (*see* Item 3.2 subparagraph 2.a.K above for further details).

This subsection has since been superseded by SIP subsection IX.H.2.d which establishes new monitoring, recordkeeping and reporting requirements for each of the limits listed in that subsection. The test methods to be used for each specific pollutant are listed in subsection IX.H.1.c, while details on the use of CEMs are covered in subsection IX.H.1.f.

2.b.G.6.{OS} Annual Emissions – established total annual emissions for the entire refinery. These annual emissions differed from the SIP Cap totals in one important aspect; the SO_2 total included values for SRU turnaround emissions (597.5 tpy) and flaring (250.0 tpy). Thus, total annual SO_2 emissions were established at 2,578.0 tons/yr.

This subsection has since been superseded by SIP subsections IX.H.2.d.i, IX.H.2.d.ii and IX.H.2.d.iii which establishes new emission Caps for each of the pollutants of concern (PM_{10}, NO_x and SO_2). These emission Caps include the potential emissions from all emission units at the refinery, including the flares.

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference. As specifically stated in subsection IX.H.1.a below, these general requirements apply to all sources subsequently listed in either IX.H.2 (Salt Lake County) or IX.H.3 (Utah County), and are in addition to (and in most cases supplemental to) any source-specific requirements found within those two subsections.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source

specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow – either in the Petroleum Refinery provisions of IX.H.1.g, or the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – General Refinery Requirements

The new maintenance plan will incorporate several new requirements that apply specifically to those petroleum refineries listed in Sections IX.H.2 and IX.H.3 of the SIP. Some subsections of IX.H.1.g also apply more broadly and could affect additional petroleum refineries in addition to those listed in the Source Specific sections which follow. Where this greater applicability exists for a particular condition or limitation, such will be noted in the discussion for that requirement.

IX.H.1.g.i.A This condition covers SO_2 emissions from fluidized catalytic cracking units (FCCUs). The limit is 50 ppmvd @ 0% excess air on a 7-day rolling average basis, as well as 25 ppmvd @ 0% excess air on a 365-day rolling average basis.

The condition is based on 40 CFR 60 Subpart Ja, and includes the same limitation found in that subpart. Compliance is demonstrated by CEM, as outlined in 40 CFR 60.105a(g) – also from Subpart Ja.

IX.H.1.g.i.B This condition addresses PM emissions from FCCUs. The limit is 1.0 lb PM per 1000 lb coke burned. The emission limit applies on a 3-hour average basis.

The emission limit is derived from 40 CFR 60 Subpart Ja, although Subpart Ja does not

specifically state that the limit applies on a 3-hour average. Instead it states that compliance will be demonstrated via a performance test using Method 5, 5b or 5f, using an average of three 60-minute (minimum) test runs.

Compliance is demonstrated by stack test as outlined in 40 CFR 60.106(b). This stack testing procedure is from Subpart J, rather than Subpart Ja. The equations utilized and reference methods involved are identical between the two subparts; however, the protocol to follow for testing is much more direct and straightforward in §60.106(b). The condition also requires the installation of a continuous parameter monitoring system (CPMS) to monitor and record operating parameters for determination of source-wide PM_{10} emissions for inclusion in the 24-hour PM_{10} Cap (see the individual source specific requirements of IX.H.2 for details on these Caps).

IX.H.1.g.ii This condition limits the H_2S content of gases burned within any refinery located within (or affecting) an area of $PM_{2.5}$ nonattainment. The limit is 60 ppm H_2S or less as described in 40 CFR 60.102a on a rolling average of 365 days.

As the $PM_{2.5}$ nonattainment areas encompasses the entirety of the PM_{10} maintenance areas this condition potentially affects more than just the four refineries listed in IX.H.2. There is at least one minor source refinery (Silver Eagle Refinery) which is affected by this requirement. The Silver Eagle Refinery was previously listed in the original SIP as Crysen Refining, Inc., but was delisted as the source is no longer a major source.

Compliance is demonstrated through continuous H_2S monitoring, as outlined in 40 CFR 60.107a. Both the limitation and the compliance methodology are based on 40 CFR 60 Subpart Ja.

IX.H.1.g.iii This condition requires the installation of SRUs that are 95% effective in removing sulfur from the streams fed to the unit; or SRUs that meet the SO2 emission requirements of Subpart Ja. The amine acid gas and sour water stripper acid gas shall be processed in the SRU(s).

This is part of condition 2.a.M.A$^{\{OS\}}$ brought forward from the original SIP. No other requirement has specifically superseded this condition, so the language has been incorporated herein.

Compliance shall be demonstrated by daily monitoring of flows to the SRUs (flow rate) and SO2 concentration in the exhaust stream (via CEM). Compliance shall be determined on a rolling 30-day average. As the specific compliance methodology was never outlined in the original SIP condition, and not clarified in any of the original specific source requirements, this requirement attempts to address this deficiency.

Small changes in the language of this condition were made to accommodate differences between the various refineries as they exist today, and to clarify the original intent of the requirement. For cases where a refinery has combined exhaust flows for control purposes, this can make monitoring of the SO2 concentration from only the SRU exhaust highly difficult. However, past testing has demonstrated that a 95% level of control across the SRU results in SO2 emissions in excess of the Subpart Ja emission standard. Therefore, meeting the NSPS emission standard will represent an equivalent or greater level of control. Smaller refineries, without tail gas incineration and not currently subject to Subpart Ja, are still subject to the existing minimum 95% level of efficiency. With respect to the amine acid gas and sour water stripper gas, this new language clarifies that it is the acid gas from these two processes that needs to be sent to the SRU, not all potential streams – some of which may be liquid streams which cannot be handled by the

SRU.

IX.H.1.g.iv This condition disallows the burning of liquid fuel oil except during natural gas curtailments and/or as specified in IX.H.2 or IX.H.3.

This is an additional part of condition 2.a.M.A{OS} brought forward from the original SIP. As with the SRU requirement addressed in the previous condition, this condition was also never superseded. The language has been incorporated herein. Specifically disallows the burning of fuel oil in refinery heaters and boilers. Specific language in the individual source requirements of IX.H.2 (and potentially IX.H.3) allows for the use of diesel-fired emergency generators and similar emergency use equipment outside of natural gas curtailment periods.

Chevron does have a specific exemption for burning HF alkylation polymer in the alky furnace. While not strictly a liquid fuel oil, the exemption is included in IX.H.2.d to add clarity and to prevent confusion.

IX.H.1.g.v This condition establishes new requirements on hydrocarbon flares.

It states that all hydrocarbon flares (defined as all non-dedicated SRU flare and header systems and all non-HF flare and header systems) are subject to Subpart Ja as of January 1, 2018 if not previously subject.

This is a simple requirement to set all the hydrocarbon flares as being subject to 40 CFR 60 Subpart Ja. It is language brought forward from the requirements of the PM2.5 SIP (Section IX.H.11.g.v.A) in order to maintain consistency between sections. Although the second paragraph of the PM2.5 SIP (IX.H.11.g.v.B) was not similarly brought forward, flare gas monitoring provisions which address the elements of that subsection can be found within each refinery's individual specific requirements of Section IX.H.2 (*see* Item 6.1 below).

5.1 Monitoring, Recordkeeping and Reporting

The new petroleum refinery requirements establish several specific emission limitations. Primarily these limits are monitored continuously – such as the SO_2 CEM on the FCCU or the H_2S monitor on fuel gas. Where continuous monitoring is used, the requirements of IX.H.1.f apply, which incorporates by reference R307-170, 40 CFR 60.13 and 40 CFR 60, Appendix B – Performance Specifications.

Under R307-170, paragraph 170-8 addresses Recordkeeping, while 170-9 addresses Reporting.

The FCCU PM limit is demonstrated by stack test. This stack test requirement is subject to the requirements of IX.H.1.e. In addition, any source with a direct stack emission limitation is subject to the requirements of R307-165.

These conditions are also subject to the general recordkeeping and reporting requirements of IX.H.1.c.

5.2 Discussion of Attainment Demonstration

PM Discussion: While the new PM limit on the FCCU might not appear to directly affect PM10 emissions, this would be incorrect. The limit is derived from the current NSPS (Subpart Ja). Under the NSPS, the assumption was that all particulate captured in the reference test method

(Method 5, 5b or 5f) would be considered as PM10. This is still the case, as compliance with the PM limit at the FCCU shall be demonstrated by stack test. Using a method 5 variant stack test allows the test to be overly conservative, as some particulate captured may fall outside the PM10 size range, and still be useful for SIP planning purposes. At the same time, it lowers the regulatory burden on the sources, by allowing each source to only have to comply with the requirements of the individual NSPS. The limit is expressed on a 3-hour block average, well below the 24-hour basis of the PM10 standard. Stack tests are required every three (3) years, which meets the minimum stack test frequency set by DAQ. Compliance is demonstrated via monitoring and use of emission factors. Stack testing serves to periodically adjust emission factors to account for significant changes in feedstocks, refinery turnarounds, or other large-scale changes that would affect the emission factor. As allowed under R307-165-2, the Director may require stack testing at any time to demonstrate compliance.

SO_2 Discussion: This is a new limitation that did not previously appear in any form in the original SIP. Although the limit is expressed on a 7-day rolling average basis, and therefore longer than the 24-hour PM_{10} standard, SO_2 emissions are eventually converted into sulfates – the particulate form. As this process takes some time to occur, and is not directly dependent on hourly or daily SO2 emissions – but rather on area average SO2 concentrations and relative chemistry – a 7-day rolling average is quite adequate to demonstrate attainment with the standard. This is especially true, given the overall daily SIP Cap – which still controls total SO2 emissions from the entire refinery. The secondary limit, expressed on a 365-day basis simply serves to keep SO2 emissions down over the long run, as well as maintaining consistency with the PM2.5 SIP requirements.

H_2S Discussion: Although the limit appears to be on a much longer averaging period than the 24-hour PM_{10} standard, the rolling 365-day calculation prevents the overall H_2S content from increasing. This in turn keeps the amount of sulfur being sent to each fuel burning device consistently low. This is also a fallback limit, like the SO2 emissions from the FCCU discussed in the previous paragraph. Total SO2 emissions are still controlled by the daily SIP Cap, regardless of the averaging period on fuel gas H2S content.

6.0 New Maintenance Plan – Chevron Specific Requirements

The Chevron specific conditions in Section IX.H.2 address those limitations and requirements that apply only to the Chevron Refinery in particular.

IX.H.2.d.i This condition establishes a source-wide Cap on PM_{10} emissions on a ton per day basis. Emissions are calculated on a filterable plus condensable basis from all sources, each day. This limit is 0.715 tons PM_{10} per day.

The condition also includes the definition of a day as being from midnight until the following midnight. Compliance 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. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.2.d.ii This condition establishes a source-wide Cap on NO_x emissions on a ton per day basis. Emissions are calculated from all emission points daily. This limit is 2.1 tons NO_x per day.

This condition includes the same definition of "day" as being from midnight until the following midnight. Compliance 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. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.2.d.iii This condition establishes a source-wide Cap on SO_2 emissions on a ton per day basis. Emissions are calculated from all emission points daily. This limit is 1.05 tons SO_2 per day.

This condition includes the same definition of "day" as both of the previous conditions as being from midnight until the following midnight. Compliance 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. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.2.d.iv This condition addresses specific fuel sulfur requirements for the refinery, allowing the use of diesel-fired emergency equipment as an exception to IX.H.1.g.iv.

Chevron currently has a number of small diesel-fired emergency engines listed in its AO. No specific provision has ever been made to allow for the use of diesel-fired emergency equipment at the refineries – and while it is clear that the provisions of 2.a.M.A$^{\{OS\}}$ were meant for the burning of liquid fuel in heaters and boilers and not for the application of emergency equipment, such language was not included nor brought forward. This condition (and similar conditions for the other refineries) addresses that oversight.

6.1 Monitoring, Recordkeeping and Reporting

Monitoring for all three conditions is addressed through a variety of methods, depending on the emission point in question. Stack testing, CEMs, parameter monitoring – all are viable options, and have been included in the language of IX.H.2.d.i through IX.H.2.d.iii. As appropriate, these monitoring requirements are complemented by the general provisions of IX.H: 1.e for stack testing, 1.f for CEMs and other continuous monitors, 1.c for recordkeeping and reporting.

Where necessary, additional monitoring, recordkeeping and/or reporting requirements have been directly included in the language of IX.H.2.d to address specific concerns. One example would be the use of leveling gauges on all fuel oil tanks to determine daily fuel oil consumption.

No specific monitoring, recordkeeping or reporting is required for IX.H.2.d.iv, as this condition serves merely as a specific exception to the general refinery requirement prohibiting the burning of liquid fuel oils. Such exception is authorized under the language of IX.H.1.g.iv itself.

Flare gas monitoring requirements – under subsection IX.H.11.g.v.B of the PM2.5 SIP, each refinery, including Chevron, is required to install and operate a flare gas recovery system or equivalent flare gas minimization process. This system needs to limit hydrocarbon flaring below 14,160 standard cubic meters (m3) (500,000 standard cubic feet (scf)) above the baseline established by the procedure outlined in 40 CFR 60.103a(a)(4). As the specific requirements of IX.H.11.g.v.B were not brought forward into the new maintenance plan, each refinery is required to include monitoring for flare gas such that total flare gas flow rate can be recorded on a daily

basis, the daily flare gas recovered for fuel gas processing can be recorded, and an estimate of daily flare gas emissions can be made. All flaring emissions are included in the daily emission Caps, and monitoring of flare gas flows satisfies both the requirements of demonstrating compliance with the daily Caps as well as subsection IX.H.11.g.v.B.

6.2 Discussion of Attainment Demonstration

Generally, the calculation methodology for determination of daily (24-hr) source-wide emissions from the Chevron refinery is identical to the method used in during the 1991/1992 timeframe of the original SIP. However, several key differences exist:

1. Emissions in the new maintenance plan are lower than in the original SIP

As is shown above in Table 3, the daily SIP Caps have dropped for all pollutants with the exception of PM10. PM10 emissions have increased primarily because of the addition of condensable emissions which were never accounted for in the original SIP. See further discussion in Item 6.2.3 below.

2. All emission units/emission points are included in the new maintenance plan

The original SIP was based on a concept of "SIP Cap sources", where only certain specific sources were included as contributing toward the emission total for a particular pollutant. Other sources, such as the flares, compressors, or SRU incinerator, would be specifically excluded from counting towards this total. This would even be spelled out by a specific requirement in the original SIP. The new maintenance plan eliminates this concept by simply stating that all sources are included, and that the emission "Caps" apply source-wide.

3. Condensable emissions, which were excluded from the original SIP, are included in the new maintenance plan

The original SIP was based on filterable PM_{10} emissions only. The new maintenance plan includes both filterable and condensable PM_{10} emissions. The 24-hour source-wide PM_{10} limit listed in IX.H.2.d.i clearly states that condensable emissions are included from all sources, and the emission factors listed in that condition include values for condensable emissions.

7.0 Interim Emission Limits and Operating Practices

When the new maintenance plan is issued and made effective, the existing SIP Sections IX.H.1-4 will be repealed and replaced. On a federal level, the currently approved 1991 PM10 State Implementation Plan will be superseded with the newest version. As many of the requirements and emission limits in IX.H.1 and IX.H.2 for the refineries have implementation dates of January 1, 2018 or January 1, 2019, an "implementation gap" could have potentially existed between the effective date of the SIP and those future compliance dates.

In order to address this concern, new Subsection IX.H.4, titled <u>Interim Emission Limits and Operating Practices</u> has been established to serve as a bridge between these two periods. For all other point sources listed in IX.H.2 and IX.H.3 the limits apply upon approval by the Utah Air Quality Board of the PM_{10} Maintenance Plan.

There are two main sections of IX.H.4: a set of general requirements that applies to all petroleum refineries in or affecting any PM10 nonattainment/maintenance area, and then a set of specific

requirements for each of the four listed refineries in IX.H.2 (BWO, Chevron, Holly and Tesoro). Both the general and specific requirements of IX.H.4 are designed to be used in conjunction with all of the requirements of IX.H.1. As these limits and operating practices are to serve only during the brief period between SIP issuance and January 1, 2019, only a bare minimum of requirements were retained. All requirements are specifically pulled from each source's latest AO, such that the source will continue to remain in compliance; however, each requirement also matches the 2005 State-only SIP. As the control technology for the sources listed in this subsection is installed and operational, the terms and conditions listed in IX.H.1 and IX.H.2 becomes applicable and those limits then replace the limits in this subsection.

For Chevron the following conditions and limitations apply during the interim period:

A. Refinery General – retention of the 9.8 kg of SO2 per 1,000 kg of coke burn-off from any Catalytic Cracking unit limit.
B. Combined emissions of filterable PM10 from all external combustion process equipment shall be no greater than 0.234 tons per day.
C. Combined emissions of sulfur dioxide from gas-fired compressor drivers and all external combustion process equipment, including the FCC CO Boiler and Catalyst Regenerator, shall not exceed 0.5 tons/day.
D. Combined emissions of NOx from gas-fired compressor drivers and all external combustion process equipment, including the FCC CO Boiler and Catalyst Regenerator and the SRU Tail Gas Incinerator, shall be no greater than 2.52 tons per day.
E. Chevron shall be permitted to combust HF alkylation polymer oil in its Alkylation unit.

Each limit has an associated compliance demonstration method and averaging period, with the exception of item E, which is the same exclusion from the "no burning of liquid fuel oil" provision (IX.H.1.g.iv.A) as that granted in IX.H.2.d.iv.B.

8.0 Implementation Schedule

The daily (24-hour) emission Caps are effective as of January 1, 2019. This schedule is dictated by the original RACT requirements established under the $PM_{2.5}$ SIP of 2014 (IX.H.11-13). In order to allow for construction, installation, shakedown and initial testing of the new equipment, this January 1, 2019 date was selected. Demonstration of attainment under the new PM_{10} maintenance plan is also set as January 1, 2019.

The provisions of IX.H.1.a-f (the General Requirements) are effective immediately upon implementation of the new maintenance plan. Those listed in IX.H.1.g (Refineries) have variable implementation dates depending on the specific provision. Some take effect immediately, while others take effect on January 1, 2018 or on January 1, 2019. Again, these dates exactly match those listed in the $PM_{2.5}$ section of the SIP (IX.H.11).

In order to address the possibility of an "implementation gap" from occurring, interim emission limits and operating practices have been established. These interim requirements are found in Subsection IX.H.4 of the new maintenance plan. For complete details on these requirements, please see Item 7.0 above.

9.0 References

Evaluation Report – Chevron Refinery

UTAH PM_{10} SIP/MAINTENANCE PLAN

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report: Hexcel

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
Hexcel Corporation

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the PM_{10} Maintenance Plan (Maintenance Plan); to address the Salt Lake County PM_{10} Nonattainment Area. This document specifically serves as an evaluation of Hexcel Corporation.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Section IX.H of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report.
- When referencing the original SIP with an effective date of August 8, 1994 the qualifier $^{\{OS\}}$ will follow any citation from that document.
- When referencing any new Maintenance Plan/SIP condition or requirement, the citation will be left blank.
- When referencing any new SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

2.0 Facility Identification

Name: Hexcel Corporation – West Valley Plant
Address: 6800 West 5400 South, West Valley City, Utah, Salt Lake County
Owner/Operator: Hexcel Corporation
UTM coordinates: 410,900 Easting 4,500,600 m Northing Zone 12

3.0 Facility Process Summary

Carbon fiber is a lightweight, high strength reinforcement material used in the manufacture of various composite structure items. The manufacturing process begins with a raw material called polyacrilonitrile (PAN).

Stabilization
In this first step, the PAN fibers are stabilized in an air oxidation process. The PAN is un-spooled, and fed into a series of low temperature (225-300° C), natural gas fueled ovens. A chemical conversion occurs as the fiber passes through the ovens, with oxidation, and polymerization taking place. This process also provides the initial alignment of the molecules in the fiber strand. The off-gas from this step in the process includes hydrogen cyanide (HCN), non-HAP VOCs, NH3, CO, and PM_{10}. The off-gas is captured by ventilation hoods at each oven or within the oven structure itself and directed to a flameless natural gas injection (NGI) dual chambered Regenerative Thermal Oxidizer (RTO) for VOC, CO, and HCN destruction and then to a baghouse for particulate removal.

Carbonization
This step includes two different phases. The first phase, tar removal, occurs within an electrically heated low temperature (300-800° C) heated furnace (LT furnace) through which the fiber continuously passes. The tar removal phase removes unwanted elements from the molecular structure and plays a key role in further aligning the polymer chain. There are no emissions associated with this process. During the entire carbon fiber manufacturing process, the PAN fibers lose approximately 50% of its original weight with the vast majority of that loss occurring in the tar removal phase. During this phase, the LT furnace is constantly blanketed with an inert atmosphere (primarily nitrogen) to prevent the fiber from self-combusting. Process emissions generated from the tar removal phase are primarily HCN, other VOCs and particulates that will be directed to a RTO/baghouse system.

The next phase occurs at higher temperatures (1,200°-1,450° C) than those of the tar removal phase. This process occurs in an electrically heated high temperature furnace (HT furnace). This phase is necessary to promote the crystalline structure growth of the molecules and to remove the final non-carbon components from the polymer rings. The resulting fiber is about 92%-95% carbon. This phase of carbonization evolves primary HCN, other VOC emissions and particulates which will be directed to a RTO/baghouse system. Once the process is at steady state, the RTO is fueled by both natural gas and other combustible gases (HCN, VOC) that are off gassing from the process.

Surface Treatment
The carbon fiber that exits the last HT furnace is at its final molecular structure. However, surface treatment is necessary in order for the finished fibers to bond with the resins that are used as binders during the manufacture of composite structures. This step involves an electrolytic process where the fiber acts as the conductor. This step involves the addition of hydroxyl units attaching to the fiber that chemically bond to the resins. The surface treatment bath is an aqueous mixture containing ammonium bicarbonate. Since this phase of the process mainly produces ammonia emissions, these emissions are not routed to the RTO/baghouse system.

Sizing
The final phase of the process may consist of an application of a thin coat of epoxy resin onto the surface of the carbon fiber that acts to hold the filaments together and improve the operability of the fiber in customer's operations. This process is referred to as the sizing operation and depending on the resin being used, it may contain a small percentage of xylene that is driven off during the drying process. Because of the very low concentration of xylene, abatement is not employed for this step, these emissions are not routed to the RTO/baghouse system.
After the sizing process, the fiber is wound into cores and packaged for shipment. The Pilot Plant is a fiber line operation but along with R&D work, specialty products are produced here (Building 2344).

Solvent Coater Prepreg (Matrix Operations)
The solvent coating operation consists of two distinct phases, the manufacture of the solvated epoxy resin and the application of the manufactured resin to the woven graphite cloth/fabric. The production of the solvated epoxy resin consists of mixing specified resins with measured amounts of MEK. The MEK carrier allows the resin to distribute evenly over and into the fabric weave (impregnate). The application of the resin to woven graphite fabric consists of a piece of machinery (solvent coater) with a series of drive rollers, a dip bath, a heated tower and a fume incinerator with heat recovery. The solvent coater assembly essentially impregnates the woven graphite fabric with a specified amount of solvated resin.

4.0 Facility Criteria Air Pollutant Emissions Sources

The facility consists of the following emission sources

- Fiber lines (2-8 and 10-16)
- Pilot furnace and ovens
- Matrix operation
- HVAC systems
- Emergency generators

5.0 Facility 2011 Baseline Actual Emissions and Current PTE

Actual emissions from Hexcel's operation in 2011 were lower than the Potential to Emit for all pollutants.

Table 1: Comparison of Actual and Potential Emissions

Pollutant	Actual Emissions (Tons/Year)[1]	Potential to Emit (Tons/Year)[2]
PM_{10}	64.58	123.81
SO_2	12.16	38.01
NO_x	108.31	168.65

[1] Hexcel's 2011 actual emissions
[2] PTE's for Hexcel's AO issued DAQE-AN113860024, dated August 11, 2015

6.0 Projected Emissions for 2019

The 2019 projected emissions were estimated with the addition of lines 12 through 16 to the actual emissions inventory submitted for 2011. Lines 12 through 16 were not permitted or constructed in 2011. NO_x emissions are primarily products of natural gas combustion.

Table 3: 2019 Projected Emission Values or Modeled Emission Values

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	70.43
SO_2	35.64
NO_x	139.47

7.0 Comparison of Requirements – Original SIP and New Maintenance Plan

Hexcel is a previously listed SIP source. In the original PM_{10} SIP document for Salt Lake County, Hexcel was included under the name Hercules Aerospace Company – Plant #3{OS}. Requirements for Hexcel are found in IX.2.2.T{OS}.

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent PM2.5 Section of the SIP. This section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM_{10} SIP sources. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11, IX.H.12 and IX.H.13 – which comprise the PM2.5 sections of the SIP, and include this additional RACT application. All requirements from the original PM_{10} SIP that have not been superseded or replaced, and which are still necessary, will also be retained. By necessary, meaning: needed in the demonstration of attainment of the 24-hour standard, or in demonstrating that no backsliding in the application of RACT has taken place.

All limits in this maintenance plan are based on the limits in the PM2.5 SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.k. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below.

7.1 SIP General Requirements

The following is a list of the requirements from the Salt Lake County {OS} SIP and a discussion of each of the requirement including current relevance and expected changes.

IX.H.2.a General Requirements{OS}

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a{OS} applied to the listed sources found in Utah County, while those found at IX.H.2.a{OS} applied to the listed sources found in Salt Lake and Davis County.

2.a.A. Stack Testing{OS} – this subsection covered the general methods and procedures for

conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which incorporates equivalent language.

2.a.B. Visible Emissions{OS} – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.C. Visible Emissions (cont.){OS} – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.D. Annual Emission Limitations{OS} – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists, and no source-specific annual SIP Caps appear in either IX.H.2 or IX.H.3 of the new maintenance plan.

2.a.E. Recordkeeping Requirements{OS} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders (AOs){OS} – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance{OS} – established that all facilities need to be adequately and properly maintained. The requirement is not needed, as this is inherent in the NSR permitting program, under R307-401-4(1).

2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. The requirement is not needed, as this is inherent in the NSR permitting program, under R307-401-3(1)(b).

2a.I. Unpaved Operational Areas{OS} – established rules for treating fugitive dust with water sprays or chemical dust suppression. This requirement has been superseded by the nonattainment area fugitive dust control requirements of R307-309.

2.a.J. Actual Emissions{OS} – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsection IX.H of the SIP.

2.a.K. Test if Directed{OS} – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test

frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions{OS} – established that the definitions contained in R307 apply to Section IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.N. Specific Fuel Requirements for Coal and/or Oil{OS} – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded by the individual source requirements found in IX.H.2 and IX.H.3 (see specifically the sources Kennecott and BYU). This requirement is now largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources have the ability to burn any other fuel oils

7.2 SIP Source Specific Requirements

The requirements and limits specific to Hexcel were extensive and will not be added to this document. Rather a summary of the requirements and highlights of the requirements will be discussed. As multiple buildings exist at Hexcel, the document was divided into general requirements, applicable to the entire source, and into building specific requirements.

The general Hexcel requirements limited visible emissions to less than or equal to 10% opacity; required that plant roads and parking lots be paved and cleaned by street vacuums; required the use of natural gas as the primary fuel in all fuel burning furnaces, ovens, incinerators, and boilers; required incinerator exhaust stacks be constructed to accommodate stack testing; and required operation of the emergency generators only when normal power sources failed, except during normal maintenance operation. In addition to the above general Hexcel requirements, natural gas consumption was limited to 175 MMSCF per year and carbon fiber production was limited to 10.8 MM pounds per year.

Visible emissions limitations do not limit emissions quantitatively. Rather they point to proper maintenance activities. These sorts of activities are inherent to the requirements from the NSR permitting program. Visible emission limits in the PM_{10} SIP are not warranted and will be removed. However, these limits will remain in the AO and the Title V requirements.

Movement of material by the haul truck and parking lots is not a significant source of emissions. In 2011, PM_{10} emissions from access roads were 0.29 tons per year. The requirements to pave and clean the roads and parking lots are not warranted and these requirements from the PM_{10} SIP will be removed.

The furnaces, ovens, incinerators and boilers at Hexcel are not capable of using a fuel other than natural gas; therefore, this requirement is not warranted and will be removed from the PM_{10} SIP.

From the 2011 emission inventory, emissions from all 14 incinerators (all operations except fiber lines 12-16) combined were 11.42 tons of PM_{10}, 38.12 tons of NO_x, and 3.96 tons of SO_2. It is not clear how requiring testing lines for the incinerators would result in meaningful emission controls or estimates. The requirement to add exhaust stacks that accommodate stack testing will be removed from the PM_{10} SIP.

The emissions from the emergency engines are each less than 5 tons per year for maintenance and testing operations and these engines are regulated by 40 CFR 63 subpart ZZZZ. Therefore, their inclusion in the PM_{10} SIP is not warranted.

The building specific requirements listed extensive equipment descriptions and operating requirements. The equipment listed in each building will be replaced with the equipment description listed in the section of this document titled Facility Criteria Air Pollutant Emissions Sources. The previous equipment list does not allow Hexcel to easily install new equipment with improved efficiencies and/or decreased emissions. The updated equipment list will allow Hexcel to update equipment more easily than the previous equipment list without modifying the PM_{10} Maintenance Plan.

Inherent in the NSR permitting program, is the requirement to determine Best Available Control Technology (BACT) for each new additional fiber line. As new controls, with corresponding decreased emissions, are determined to be BACT, Hexcel will be required to include this new level of control with each successive fiber line addition. The addition of a fiber line with higher emissions than existing lines will not be permitted through the NSR permitting program.

7.3 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference. As specifically stated in subsection IX.H.1.a below, these general requirements apply to all sources subsequently listed in either IX.H.2 (Salt Lake County) or IX.H.3 (Utah County), and are in addition to (and in most cases supplemental to) any source-specific requirements found within those two subsections.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum

period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions. This recordkeeping requirement includes records of startup/shutdown implementation procedures, as well as CEMS testing data and stack testing data, as applicable.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

7.4 New Maintenance Plan – Hexcel Specific Requirements

IX.H.2.e Hexcel Corporation: Salt Lake Operations

i. The following limits shall not be exceeded for fiber line 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 and onsite metering.

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

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

ii. After a shutdown and prior to startup of a fiber line, all control equipment shall be started and remain in operation during production. Control equipment on each fiber line may consist of incinerators, baghouses, and regenerative thermal oxidizers.
   a. Compliance with control equipment operation during production shall be determined by keeping record of control equipment that is not operating on the fiber line(s) in production.

Discussion – The natural gas and fiber production limits were changed from the yearly limits given in the 1994 SIP to daily limits. These limits were determined by dividing the yearly natural gas consumption limit by 365 days per year and then multiplying this value by a 30 % peaking factor. An analysis of Hexcel's historical daily production from 2006 to 2012 showed that on average the peak daily production was approximately 42%. DAQ selected a 30 % rather than a 42 % peaking factor into the calculation of the daily consumption and production limits. Emission calculations to convert yearly natural gas consumption and carbon fiber production limits are provided in the appendix. AP-42 or equipment specific emission factors are used to calculate emissions. A daily emission limit, rather than a yearly limit, was included as a 24-hour PM_{10} standard now applies.

Incinerators and regenerative thermal oxidizers reduce VOCs and CO emissions. PM emissions are reduced with baghouses.

8.0 Monitoring, Recordkeeping and Reporting

Compliance monitoring of the limits is given in IX.H.2.e.i.c. Hexcel monitors its daily production and natural gas combustion limits through examination of production records and

natural gas billing records.

All common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

9.0 Discussion of Attainment Demonstration

The general requirements act as a framework that the other requirements can build. Second, they demonstrate a prevention of backsliding. Through the use of general requirements that are either the same as or functionally equivalent to those in the 1994 Original SIP, backsliding has been prevented. Finally, when a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument could be made in that regard, the requirement was simply removed.

Hexcel has added new lines, and increased natural gas consumption and carbon production limits, through the use of offsets during the AO modification process. The AOs that required the use of offsets were DAQE-AN1386014-06, dated October 23, 2006 and DAQE-AN0113860016-08, dated September 18, 2008, DAQE-AN113860019-11, dated December 28, 2011, and DAQE-AN113860024-15, dated August 11, 2015. Backsliding has been prevented as permitted emission increases since 1994 have been offset under the PM_{10} offsetting program with a ratio of at least 1:1.

Source specific limits are equivalent to the requirements from the 1994 Original SIP. The original SIP included yearly natural gas consumption and production limits, rather than emission limits with stack testing to verify emission factors.

10.0 Implementation Schedule

The requirements imposed on the Hexcel are effective immediately. It did not have any required RACT modifications to undertake from the PM2.5 SIP RACT requirements. Therefore, the natural gas consumption and carbon fiber production limits listed in IX.H.3.g can be applied immediately. Similarly, the general requirements, IX.H.1.a-f, can also be applied immediately.

11.0 Daily Emissions

Potential daily emission estimates from the 1994 SIP and current operations shows that emissions have increased, as described in Table 3. Offsets have been used with these emission increases, as discussed in the prior sections of this document, to prevent backsliding.

The potential daily emission estimates from the 1994 SIP were calculated assuming the yearly emission estimates were evenly divided over 365 days per year. The potential daily emission estimates for the currently permitted operations, AO DAQE-AN113860024, dated August 11, 2015, were calculated assuming that yearly PTE for each pollutant that was increased by a 30% peaking factor and divided evenly over 365 days per year. This was the same process used to calculate the daily natural gas consumption and fiber line production limits during the

preparation of the $PM_{2.5}$ SIP. The daily emission estimates or emissions from individual fiber lines are equivalent to the emissions resulting from the daily natural gas consumption and fiber production limits. Calculations are further described in the appendix.

. **Table 3: Yearly Emission Estimates and Potential Daily Emissions**

All values in tons	Original SIP NO_x	NO_x	Original SIP SO_2	SO_2	Original SIP PM_{10}	PM_{10}
Annual Emissions	98.9{OS}	193.32**	0.1{OS}	49.26**	76.8{OS}	123.81**
Daily (24-hr)	0.27*	0.69***	>0.01*	0.18***	0.21*	0.44***

* Assumes NO_x annual emission estimates divided by 365 days per year.
**PTE from AO DAQE-AN113860023, dated January 8, 2015 (all fiber lines except lines 15-16)
***Assumes PTE from AO DAQE-AN113860024, dated August 11, 2015 increased by a 30% peaking factor and divided by 365 days per year

12.0 References

Evaluation Report –

UTAH PM_{10} /Maintenance Plan

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report:
Holly Refining and Marketing Company – Woods Cross, LLC.

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
Holly Refinery

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the Utah Implementation Plan (SIP); to address the Salt Lake County PM_{10} Nonattainment Area (SLCNA). This document specifically serves as an evaluation of the Holly Refinery.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Sections IX.H.1-4 of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report. However, see Section 7.0 of this document for some clarification.
- When referencing the original SIP with an effective date of August 8, 1994 the qualifier $^{\{OS\}}$ will follow any citation from that document.
- In reference to the updated Utah County SIP with an effective date of January 22, 2003 the qualifier $^{\{UC\}}$ will follow any citation from that document.
- When referencing any new Maintenance Plan/SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Holly Refinery
Address: 393 South 800 West, Woods Cross, Utah, Davis County
Owner/Operator: Holly Refining & Marketing Company – Woods Cross, LLC
UTM coordinates: 4,526,227 m Northing, 424,000 m Easting, Zone 12

1.2 Facility Process Summary

The Holly Refinery (Holly) is a petroleum refinery capable of processing 60,000 barrels per day of crude oil, primarily heavier black wax and yellow wax crudes from eastern Utah. The source consists of two FCCUs, both controlled with wet gas scrubbers. A single sulfur recovery unit controls the sulfur content of the fuel gas. The source also has the usual assorted heaters, boilers, cooling towers, storage tanks, flares, and related fugitive emissions – primarily VOCs.

The two FCCUs are both complete burn units without cokers. There are no cogeneration units present. The refinery currently operates without flare gas recovery.

1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of the main emitting units from the Holly Refinery:

- Fluid Catalytic Cracking Unit (FCCU) #1, controlled with a wet gas scrubber (WGS)
- FCC Feed Heater, 68.4 MMBtu/hr process furnace, fired on plant gas, restricted to 39.9 MMBtu/hr, equipped with low NO_x burners (LNB)
- Reformer charge and reheater furnace/waste heat boiler, 54.7 MMBtu/hr process furnace, fired on plant gas
- Prefractionator Reboiler Heater, 12.0 MMBtu/hr process furnace, fired on plant gas
- Reformer Reheat Furnace, 37.7 MMBtu/hr process furnace, fired on plant gas
- HF Alkylation Regeneration Furnace, 4.4 MMBtu/hr process furnace, fired on plant gas
- HF Alkylation Depropanizer Reboiler, 33.3 MMBtu/hr process furnace, fired on plant gas
- Crude Furnace #1, 99.0 MMBtu/hr process furnace, fired on plant gas, equipped with next generation ultra-low NO_x burner (NGULNB)
- Distillate Hydrosulfurization (DHDS) Unit Reactor Charge Heater, 8.1 MMBtu/hr process furnace, fired on plant gas
- DHDS Stripper Reboiler, 4.1 MMBtu/hr process furnace, fired on plant gas
- Asphalt Mix Heater, 13.2 MMBtu/hr process furnace, fired on plant gas
- Hot Oil Furnace, 99 MMBtu/hr process furnace, fired on plant gas, equipped with LNB and selective catalytic reduction (SCR) system
- Straight Run Gas Plant (SRGP) Depentanizer Reboiler, 24.2 MMBtu/hr process furnace, fired on plant gas
- Naphtha Hydrodesulphurization (NHDS) Unit Reactor Charge Furnace, 50.2 MMBtu/hr process furnace, fired on plant gas, equipped with NGULNB
- Isomerization Reactor Feed Furnace 6.5 MMBtu/hr process furnace, fired on plant gas
- Sulfur Recovery (SRU) with Tailgas Incinerator
- Distillate Hydrodesulfurization Treatment (DHT) Reactor Charge Heater, 18.1 MMBtu/hr process furnace, fired on plant gas, equipped with LNB
- Gas Oil Hydrocracking (GHC) Unit Reactor Charge Heater, 14.9 MMBtu/hr process furnace, fired on plant gas, equipped with ultra-low NO_x Burners (ULNB)
- Fractionator Charge Heater, 47.0 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB
- Fractionator Charge Heater, 42.1 MMBtu/hr furnace, fired on plant gas, equipped with ULNB
- Reformate Splitter Reboiler Heater, 21.0 MMBtu/hr heater, fired on plant gas, equipped with ULNB
- Crude Unit Furnace, 60.0 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB

- FCCU #2, controlled with WGS and LoTOx
- FCC Feed Heater 45 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB
- Hydrocracker/Hydroisom Unit Reactor Charger Heater, 99.0 MMBtu/hr reactor charger heater, fired on plant gas, equipped with LNB and SCR
- Hydrogen Reformer Feed Furnace, 123.1 MMBtu/hr process furnace, fired on plant gas, equipped with LNB and SCR
- Hydrogen Reformer Feed Furnace, 123.1 MMBtu/hr process furnace, fired on plant gas, equipped with LNB and SCR
- Vacuum Furnace Heater, 130.0 MMBtu/hr heater, fired on plant gas, equipped with LNB and SCR
- Boiler #4, 35.6 MMBtu/hr boiler, fired on plant gas
- Boiler #5, 70.0 MMBtu/hr boiler, fired on plant gas, equipped with SCR
- Boiler #8, 92.7 MMBtu/hr boiler, fired on plant gas, equipped with LNB and SCR
- Boiler #9, 89.3 MMBtu/hr boiler, fired on plant gas, equipped with SCR
- Boiler #10, 89.3 MMBtu/hr boiler, fired on plant gas, equipped with SCR
- Boiler #11, 89.3 MMBtu/hr steam boiler, fired on plant gas, equipped with LNB and SCR
- Cooling Towers
- Flares
- Tank Farm
- Loading/Unloading
- Emergency Equipment (Diesel)
- Emergency Equipment (Natural Gas)

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at the refinery, rather it is a listing of all significant emission units or emission unit groups (such as the tank farm).

1.4 PM2.5 SIP New Equipment

As part of the RACT requirements for the PM2.5 SIP, Holly is in the process of making equipment upgrades which will be completed prior to the attainment demonstration date of the new maintenance plan (January 1, 2019). Although these upgrades are not yet installed, the new equipment has been included in the modeled attainment demonstration; by including the effects of the equipment on total emissions from the refinery.

Holly is adding a second WGS unit to control emissions from the newly installed FCCU #2. A new more efficient cooling tower will be installed, and several compressor engines will be converted to electric operation. Both of these changes have been included in the emission calculation spreadsheet used as primary input for the attainment demonstration model. The new WGS controls particulates, NOx and SO2 emissions, while the conversion of the compressor engines has completely eliminated combustion emissions from those sources.

One additional control system is the requirement to install and operate a flare gas recovery system or equivalent flare gas minimization process. This system must be installed an operational no later than January 1, 2019 – again, before the attainment demonstration date. The requirement for this system is found within the refinery general requirements of Section IX.H.11 of the SIP, specifically IX.H.11.g.v.B. Although no equivalent requirement was brought forward into the PM10 Section of the new maintenance plan, Holly (as with all the refineries) does have additional requirements in its listing in Section IX.H.2 to account for monitoring of flare gas flow – either to demonstrate flare gas recovery, or to account for flaring emissions as part of the overall daily

Caps. The monitoring requirements will address both PM10 and PM2.5 needs. See Items 5 and 6 below for additional details.

1.5 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, Holly's baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	54.45
SO_2	131.03
NO_x	208.46

The current PTE values for Holly, as established by the most recent AO issued to the source (DAQE-AN101230041-13) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	147.8
SO_2	110.3
NO_x	341.1

However, please see the discussion in Section 2.0 (and Table 3) below for further details on Holly's PTE value.

2.0 Modeled Emission Values

Unlike the base year inventory, which used only the 2011 actual emissions for each source to set the baseline for modeling, a modified version of the PTE values was used for the modeled attainment demonstration. Generally for each refinery, beginning with the PTE values listed in Table 2 (from the most recent approval order issued to each source), these values were "trued-up" by including the expected effects from implementation of RACT from the PM2.5 SIP. This yields a 2019 Projected Emission Value for each of the pollutants of concern. Where necessary, these values were corrected for condensable particulates using simple correction factors based on fuel consumed or process type.

Where gaseous fuels, such as natural gas or refinery fuel gas, were combusted, filterable-only emissions were converted to a filterable+condensable emission value by multiplying the filterable rate by 4. Liquid fuels, such as diesel fuel #2, were converted using the latest AP-42 emission factors. Processes such as cooling towers, which emit largely filterable-only emissions, were not adjusted. Other processes were adjusted, as needed, on a case-by-case basis using the best data available – primarily the latest stack test information.

For the Holly Refinery specifically, these additional steps were not required. The AO issued to Holly in 2013 included the expected application of RACT as well as the assumption that both filterable and condensable emissions would be limited. Therefore, for the Holly Refinery, no change occurs between the values in Table 2 and the Modeled Emission Values listed in Table 3, as shown below:

Table 3: Modeled Emission Values

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	147.8
SO_2	110.3
NO_x	341.1

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent PM2.5 Section of the SIP. This Section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM10 SIP sources – including the refineries in general, and the Holly Refinery in specific. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11-13 – which comprise the PM2.5 sections of the SIP, and include this additional RACT application. All requirements from the original PM10 SIP that have not been superseded or replaced, and which are still necessary, will also be retained. By necessary, meaning: significant from the standpoint of PM10 control, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

Holly is a previously listed SIP source. In the original PM_{10} SIP, Holly was listed in Subsection IX.H.2.b.OO$^{\{OS\}}$ as Phillips 66 Company – Woods Cross. As a listed source there were several requirements and conditions that applied to the facility.

In addition, Holly is also a listed source in the PM2.5 Section of the SIP (see SIP Section IX.H.12.k). As was discussed above in Item 2.0, all limits in this maintenance plan are based on the limits in the December 3, 2014 PM2.5 SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.k. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below:

3.1 Original SIP General Requirements

IX.H.2.a General Requirements$^{\{OS\}}$

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a$^{\{OS\}}$ applied to the listed sources found in Utah County, while those found at IX.H.2.a$^{\{OS\}}$ applied to the listed sources found in Salt Lake and Davis County. As the then Phillips Refinery was located in Davis County, only the general requirements of IX.H.2.a$^{\{OS\}}$ applied. However, except for the additional requirements found under IX.H.2.a.M$^{\{OS\}}$ for petroleum refineries and the specific fuel requirements of IX.H.2.a.N$^{\{OS\}}$, the two subsections are essentially identical.

2.a.A. Stack Testing$^{\{OS\}}$ – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which serves the same purpose.

2.a.B. Visible Emissions$^{\{OS\}}$ – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which serves the same purpose.

2.a.C. Visible Emissions (cont.)$^{\{OS\}}$ – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.D. Annual Emission Limitations$^{\{OS\}}$ – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists, and no source-specific annual SIP Caps appear in either IX.H.2 or IX.H.3 of the new maintenance plan.

2.a.E. Recordkeeping Requirements$^{\{OS\}}$ – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders$^{\{OS\}}$ – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance$^{\{OS\}}$ – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program, under R307-401-4(1).

2.a.H. Future Modifications$^{\{OS\}}$ – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program, under R307-401-3(1)(b).

2a.I. Unpaved Operational Areas$^{\{OS\}}$ – established rules for treating fugitive dust with water sprays or chemical dust suppression. This requirement has been superseded by the fugitive dust rules of R307-205 and R307-1-4.5, or the most recent federally approved fugitive dust rule.

2.a.J. Actual Emissions$^{\{OS\}}$ – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsections IX.H.1-4 of the SIP. This requirement is outdated and obsolete.

2.a.K. Test if Directed$^{\{OS\}}$ – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions$^{\{OS\}}$ – established that the definitions contained in R307 apply to subsection IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.N. Specific Fuel Requirements for Coal and/or Oil$^{\{OS\}}$ – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded by the individual source requirements found in IX.H.2 and IX.H.3 (see specifically the sources Kennecott and BYU). This requirement is now largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel

fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources have the ability to burn any other fuel oils.

3.2 Original SIP Petroleum Refinery Requirements

2.a.M. Petroleum Refineries{OS} – This is a fairly lengthy subsection pertaining only to the petroleum refineries. This subsection has its own sub-subsections, owing to the overall length and complexity.

2.a.M.A. Sulfur Recovery Units (SRUs){OS} – established the requirement for 95% efficient SRUs, no burning of liquid fuel oil except during natural gas curtailments, use of low-SO_x catalyst to attain a 9.8 kg SO_2/1000 kg coke burnoff in FCC units, amine and sour water overhead streams shall also be processed in the SRU. These conditions currently remain in effect. The SO_2 limit is largely irrelevant as the limitation in SIP subsection IX.H.1.g.i.A.I is based on 40 CFR 60, Subpart Ja, and is more stringent. The other three requirements: 95% efficient SRUs, no burning of liquid fuel oil, & amine and sour water overhead streams being processed in the SRU, shall be retained. These three conditions are found at SIP subsections IX.H.1.g.iii, IX.H.1.g.iv, and IX.H.1.g.iii, respectively.

2.a.M.B. Routine Turnaround Periods{OS} – established exclusion periods when routine turnarounds of the SRUs could be performed, and the procedure for scheduling one of these periods. These conditions are no longer required. Each of the refineries has agreed to incorporate alterative language which supersedes these requirements. In Holly's specific case, the refinery has opted to install two WGS systems. These systems are sized such that all additional emissions from a SRU turnaround can be accommodated within the established 24-hour emission Caps – including all flaring and additional SO_2.

2.a.M.C.1. Compliance Demonstration part 1{OS} – established that SRU turnaround emissions and flaring emissions are not included in either the daily (24-hour) or annual compliance demonstrations. As with 2.a.M.B{OS} above, this requirement is no longer required. Each refinery has agreed to alternative language regarding SRU turnarounds. All flaring emissions have been included in the 24-hour emission Caps for each listed refinery. Further, flares are also addressed with SIP subsection IX.H.1.g.v.B which covers flare gas recovery systems.

2.a.M.C.2. Compliance Demonstration part 2{OS} – established how the daily (24-hr) emissions limits (Caps) would be determined, including recordkeeping and reporting requirements. This subsection has since been superseded by the individual source's SIP subsection (for Holly, this would be Section IX.H.2.f) which establishes the 24-hour emission limits, and the monitoring, recordkeeping and reporting requirements associated with those limits.

2.a.M.C.3. Compliance Demonstration part 3{OS} – established a methodology for how emission limits could be modified/adjusted as necessary. This subsection is no longer required, as this procedure is no longer followed.

2.a.M.C.4. Compliance Demonstration part 4{OS} – also established that annual emissions for refineries followed a process essentially identical to the rolling 12-month process outlined above in 2.a.D{OS}. This subsection is no longer required as the specific requirement to track annual emissions is no longer needed with the removal of the annual PM10 standard.

2.a.M.D. Process Flaring Emissions and Routine Turnaround Emissions$^{\{OS\}}$ – established that both sets of emissions were included in the modeled attainment demonstration. This subsection is no longer required, as a new attainment demonstration has been performed and both process flaring and routine turnaround emissions are handled differently in the new maintenance plan. See SIP subsection IX.H.1.g.v.B which covers flare gas recovery systems. SRU routine turnarounds requirements have been removed from the new maintenance plan.

3.3 Original SIP Source Specific Requirements

Individual source requirements:

2.b.OO.1.$^{\{OS\}}$ This subsection was a listing of the equipment at the refinery – this subsection has been superseded and is irrelevant. A simple listing of equipment does not constitute an emission limitation, does not impose any restriction on daily emissions, and rapidly becomes out of date as well as impossible to enforce. The original listing found in this subsection does not match the current equipment installed and operating at the refinery and would represent a significant step backwards in emission control and refining technology.

2.b.OO.2.$^{\{OS\}}$ Basis for SO_2 Emission Limitations – A) established the SO_2 daily and annual emission Caps. B) established the sources included in the SO_2 emissions Caps. C) established that the SO_2 emission Caps shall be determined by multiplying the amount of each type of fuel burned each day by specific emission factors listed in this subsection [2.B.OO.2.C) $^{\{OS\}}$.], and that the quantity of each fuel burned would need to be monitored/recorded appropriately. D) was supposed to establish individual point source limitations for specific TCC emission units and the SRU tail gas incinerator (these were never revisited in the context of the SIP). E) established that stack testing would be performed as outlined in SIP subsections 2.b.OO.5$^{\{OS\}}$, 2.a.A$^{\{OS\}}$ and 2.1.M$^{\{OS\}}$. F) established that the flares were not included in the SO_2 Caps, and also not regulated for SO_2 emissions.

This subsection has since been superseded by the SIP subsection which establishes new plantwide SO_2 daily (24-hour) emission Caps (for Holly, this would be Section IX.H.2.f.iii). These new SO_2 emission Caps cover all emission units at the refinery – including the flares – so no emission unit is excluded. The new SO_2 emission Caps are significantly lower than the original Caps (see the comparison in Table 4 below). Although no annual standard for PM10 remains, the anticipated annual numbers have been included for easy comparison with the original SIP values. The compliance methodology included in SIP subsection IX.H.2.f.iii also includes the calculation of amount of fuel burned multiplied by the emission factor for each fuel type – although these emission factors have been updated as needed. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below).

2.b.OO.3.$^{\{OS\}}$ Basis for the NO_x Emission Limitations – Similar to the SO_2 limitations above: A) established the NO_x daily and annual emission Caps. B) established the sources included in the NO_x emissions Caps. C) established that the NO_x emission Caps shall be determined by multiplying the amount of each type of fuel burned each day by specific emission factors listed in this subsection [2.B.OO.3.C)$^{\{OS\}}$.], and that the quantity of each fuel burned would need to be monitored/recorded appropriately. D) established that the flares were not included in the NO_x Caps, and also not regulated for NO_x emissions.

This subsection has since been superseded by SIP subsection IX.H.2.f.ii which establishes new plantwide NO_x daily (24-hour) emission Caps. As with the SO_2 emission Caps, these new NO_x

emission Caps cover all emission units at the refinery – including the flares. The new NO_x emission Caps are also lower than the original Caps (again, the table also includes the expected annual emission values as a convenient comparison with the original SIP emissions). Again, the compliance methodology included in SIP subsection IX.H.2.f.ii uses the amount of fuel burned multiplied by the emission factor for each fuel type. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below).

2.b.OO.4.{OS} Basis for the PM_{10} Emission Limitations – As with both the SO_2 and NO_x limitations listed above: A) established the PM_{10} daily and annual emission Caps. B) established the sources included in the PM_{10} emissions Caps. C) established that the PM_{10} emission Caps shall be determined by multiplying the amount of each type of fuel burned each day by specific emission factors listed in this subsection [2.B.OO.3.C){OS}.], and that the quantity of each fuel burned would need to be monitored/recorded appropriately. D) established an individual point source limitation for the TCC lift air heater/circulation system. E) established that stack testing would be performed as outlined in SIP subsections 2.b.OO.5{OS}, and 2.a.A{OS}. F) established that the flares and several compressor engines were not included in the PM_{10} Caps, and also not regulated for PM_{10} emissions.

This subsection has since been superseded by SIP subsection IX.H.2.f.i which establishes new plantwide PM_{10} daily (24-hour) emission Caps. As with both the SO_2 and NO_x emission Caps, these new PM_{10} emission Caps cover all emission units at the refinery – including the flares. While the compressor engines are technically also included, the majority of these engines have either been replaced with electric motors or had the gas-fired drivers replaced with electric drivers. This renders these engines as non-emitting units. The new PM_{10} emission Caps are also lower than the original Caps, on both an annual and 24-hour basis (annual values listed for comparison purposes as with SO2 and NOx). As before, the compliance methodology included in SIP subsection IX.H.2.f.i uses the amount of fuel burned multiplied by the emission factor for each fuel type. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below).

Table 3: Comparison Table – Old SIP Caps vs New SIP Caps

	SO_2 Original	**SO_2 New**	**NO_x Original**	**NO_x New**	**PM_{10} Original**	**PM_{10} New**
Annual	1,762.0*	110.3	693.0	341.1	160.9$	147.8&
Daily (24-hr)	4.705	0.31	2.20	2.09	0.441$	0.42&

* SIP Cap sources only (total annual emissions are listed in 2.b.OO.6 below)
$ filterable emissions only
& includes condensable emissions

2.b.OO.5.{OS} Stack Testing Requirements – established which point sources were required to comply with specific emission limitations (established in preceding paragraphs), the test method to be used to verify compliance (including CEMs if applicable), and the frequency of testing and/or monitoring.

This subsection has since been superseded by SIP subsection IX.H.2.f which establishes new monitoring, recordkeeping and reporting requirements for each of the limits listed in that subsection. The test methods to be used for each specific pollutant are listed in subsection IX.H.1.c. While details on the use of CEMs is covered in subsection IX.H.1.f.

2.b.OO.6.{OS} Annual Emissions – established total annual emissions for the entire refinery. These annual emissions differed from the SIP Cap totals in one important aspect; the SO_2 total included values for SRU turnaround emissions (136 tpy), and estimated process flaring emissions (118 tpy). Thus, total annual SO_2 emissions were established at 2,016.0 tons/yr.

This subsection has since been superseded by SIP subsections IX.H.2.f.i, IX.H.2.f.ii and IX.H.2.f.iii which establishes new emission Caps for each of the pollutants of concern (PM_{10}, NO_x and SO_2). These emission Caps include the potential emissions from all emission units at the refinery, including the flares.

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference. As specifically stated in subsection IX.H.1.a below, these general requirements apply to all sources subsequently listed in either IX.H.2 (Salt Lake County) or IX.H.3 (Utah County), and are in addition to (and in most cases supplemental to) any source-specific requirements found within those two subsections.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for

demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow – either in the Petroleum Refinery provisions of IX.H.1.g, or the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – General Refinery Requirements

The new maintenance plan will incorporate several new requirements that apply specifically to those petroleum refineries listed in Sections IX.H.2 and IX.H.3 of the SIP. Some subsections of IX.H.1.g also apply more broadly and could affect additional petroleum refineries in addition to those listed in the Source Specific sections which follow. Where this greater applicability exists for a particular condition or limitation, such will be noted in the discussion for that requirement.

IX.H.1.g.i.A This condition covers SO_2 emissions from fluidized catalytic cracking units (FCCUs). The limit is 50 ppmvd @ 0% excess air on a 7-day rolling average basis, as well as 25 ppmvd @ 0% excess air on a 365-day rolling average basis.

The condition is based on 40 CFR 60 Subpart Ja, and includes the same limitation found in that subpart. Compliance is demonstrated by CEM, as outlined in 40 CFR 60.105a(g) – also from Subpart Ja.

IX.H.1.g.i.B This condition addresses PM emissions from FCCUs. The limit is 1.0 lb PM per 1000 lb coke burned. The emission limit applies on a 3-hour average basis.

The emission limit is derived from 40 CFR 60 Subpart Ja, although Subpart Ja does not specifically state that the limit applies on a 3-hour average. Instead it states that compliance will be demonstrated via a performance test using Method 5, 5b or 5f, using an average of three 60-minute (minimum) test runs.

Compliance is demonstrated by stack test as outlined in 40 CFR 60.106(b). This stack testing procedure is from Subpart J, rather than Subpart Ja. The equations utilized and reference methods involved are identical between the two subparts; however, the protocol to follow for testing is much more direct and straightforward in §60.106(b). The condition also requires the installation of a continuous parameter monitoring system (CPMS) to monitor and record operating parameters for determination of source-wide PM_{10} emissions for inclusion in the 24-hour PM_{10} Cap (see the individual source specific requirements of IX.H.2 for details on these Caps).

IX.H.1.g.ii This condition limits the H_2S content of gases burned within any refinery located within (or affecting) an area of $PM_{2.5}$ nonattainment. The limit is 60 ppm H_2S or less as described in 40 CFR 60.102a on a rolling average of 365 days.

As the $PM_{2.5}$ nonattainment areas encompasses the entirety of the PM_{10} maintenance areas this condition potentially affects more than just the four refineries listed in IX.H.2. There is at least one minor source refinery (Silver Eagle Refinery) which is affected by this requirement. The Silver Eagle Refinery was previously listed in the original SIP as Crysen Refining, Inc., but was delisted as the source is no longer a major source.

Compliance is demonstrated through continuous H_2S monitoring, as outlined in 40 CFR 60.107a. Both the limitation and the compliance methodology are based on 40 CFR 60 Subpart Ja.

IX.H.1.g.iii This condition requires the installation of SRUs that are 95% effective in removing sulfur from the streams fed to the unit; or SRUs that meet the SO2 emission requirements of Subpart Ja. The amine acid gas and sour water stripper acid gas shall be processed in the SRU(s).

This is part of condition 2.a.M.A$^{\{OS\}}$ brought forward from the original SIP. No other requirement has specifically superseded this condition, so the language has been incorporated

herein.

Compliance shall be demonstrated by daily monitoring of flows to the SRUs (flow rate) and SO2 concentration in the exhaust stream (via CEM). Compliance shall be determined on a rolling 30-day average. As the specific compliance methodology was never outlined in the original SIP condition, and not clarified in any of the original specific source requirements, this requirement attempts to address this deficiency.

Small changes in the language of this condition were made to accommodate differences between the various refineries as they exist today, and to clarify the original intent of the requirement. The Holly refinery has combined the exhaust flows from the SRU and the FCCU so that they are controlled jointly by a wet gas scrubber. This makes monitoring of the SO2 concentration from only the SRU exhaust highly difficult. However, past testing has demonstrated that a 95% level of control across the SRU results in SO2 emissions in excess of the Subpart Ja emission standard. Therefore, meeting this emission standard will represent an equivalent or greater level of control. With respect to the amine acid gas and sour water stripper gas, this new language clarifies that it is the acid gas from these two processes that needs to be sent to the SRU, not all potential streams – some of which may be liquid streams which cannot be handled by the SRU.

IX.H.1.g.iv This condition disallows the burning of liquid fuel oil except during natural gas curtailments and/or as specified in IX.H.2 or IX.H.3.

This is an additional part of condition 2.a.M.A$^{\{OS\}}$ brought forward from the original SIP. As with the SRU requirement addressed in the previous condition, this condition was also never superseded. The language has been incorporated herein. Specifically disallows the burning of fuel oil in refinery heaters and boilers. Specific language in the individual source requirements of IX.H.2 (and potentially IX.H.3) allows for the use of diesel-fired emergency generators and similar emergency use equipment outside of natural gas curtailment periods.

IX.H.1.g.v This condition establishes new requirements on hydrocarbon flares.

It states that all hydrocarbon flares (defined as all non-dedicated SRU flare and header systems and all non-HF flare and header systems) are subject to Subpart Ja as of January 1, 2018 if not previously subject.

This is a simple requirement to set all the hydrocarbon flares as being subject to 40 CFR 60 Subpart Ja. It is language brought forward from the requirements of the PM2.5 SIP (Section IX.H.11.g.v.A) in order to maintain consistency between sections. Although the second paragraph of the PM2.5 SIP (IX.H.11.g.v.B) was not similarly brought forward, flare gas monitoring provisions which address the elements of that subsection can be found within each refinery's individual specific requirements of Section IX.H.2 (*see* Item 6.1 below).

5.1 Monitoring, Recordkeeping and Reporting

The new petroleum refinery requirements establish several specific emission limitations. Primarily these limits are monitored continuously – such as the SO_2 CEM on the FCCU or the H_2S monitor on fuel gas. Where continuous monitoring is used, the requirements of IX.H.1.f apply, which incorporates by reference R307-170, 40 CFR 60.13 and 40 CFR 60, Appendix B – Performance Specifications.

Under R307-170, paragraph 170-8 addresses Recordkeeping, while 170-9 addresses Reporting.

The FCCU PM limit is demonstrated by stack test. This stack test requirement is subject to the requirements of IX.H.1.e. In addition, any source with a direct stack emission limitation is subject to the requirements of R307-165.

These conditions are also subject to the general recordkeeping and reporting requirements of IX.H.1.c.

5.2 Discussion of Attainment Demonstration

PM Discussion: While the new PM limit on the FCCU might not appear to directly affect PM10 emissions, this would be incorrect. The limit is derived from the current NSPS (Subpart Ja). Under the NSPS, the assumption was that all particulate captured in the reference test method (Method 5, 5b or 5f) would be considered as PM_{10}. This is still the case, as compliance with the PM limit at the FCCU shall be demonstrated by stack test. Using a method 5 variant stack test allows the test to be overly conservative, as some particulate captured may fall outside the PM_{10} size range, and still be useful for SIP planning purposes. At the same time, it lowers the regulatory burden on the sources, by allowing each source to only have to comply with the requirements of the individual NSPS. The limit is expressed on a 3-hour block average, well below the 24-hour basis of the PM_{10} standard. Stack tests are required every three (3) years, which meets the minimum stack test frequency set by DAQ. Compliance is demonstrated via monitoring and use of emission factors. Stack testing serves to periodically adjust emission factors to account for significant changes in feedstocks, refinery turnarounds, or other large-scale changes that would affect the emission factor. As allowed under R307-165-2, the Director may require stack testing at any time to demonstrate compliance.

SO_2 Discussion: This is a new limitation that did not previously appear in any form in the original SIP. Although the limit is expressed on a 7-day rolling average basis, and therefore longer than the 24-hour PM_{10} standard, SO_2 emissions are eventually converted into sulfates – the particulate form. As this process takes some time to occur, and is not directly dependent on hourly or daily SO2 emissions – but rather on area average SO2 concentrations and relative chemistry – a 7-day rolling average is quite adequate to demonstrate attainment with the standard. This is especially true, given the overall daily SIP Cap – which still controls total SO2 emissions from the entire refinery. The secondary limit, expressed on a 365-day basis simply serves to keep SO2 emissions down over the long run, as well as maintaining consistency with the PM2.5 SIP requirements.

H_2S Discussion: Although the limit appears to be on a much longer averaging period than the 24-hour PM_{10} standard, the rolling 365-day calculation prevents the overall H_2S content from increasing. This in turn keeps the amount of sulfur being sent to each fuel burning device consistently low. This is also a fallback limit, like the SO2 emissions from the FCCU discussed in the previous paragraph. Total SO2 emissions are still controlled by the daily SIP Cap, regardless of the averaging period on fuel gas H2S content.

6.0 New Maintenance Plan – Holly Specific Requirements

The Holly specific conditions in Section IX.H.2 address those limitations and requirements that apply only to the Holly Refinery in particular.

IX.H.2.f.i This condition establishes a source-wide Cap on PM_{10} emissions on a ton per day basis. Emissions are calculated on a filterable plus condensable basis from all

sources, each day. This limit is 0.416 tons PM_{10} per day.

The condition also includes the definition of a day as being from midnight until the following midnight. Compliance 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. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.2.f.ii This condition establishes a source-wide Cap on NO_x emissions on a ton per day basis. Emissions are calculated from all emission points daily. This limit is 2.09 tons NO_x per day.

This condition includes the same definition of "day" as being from midnight until the following midnight. Compliance 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. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.2.f.iii This condition establishes a source-wide Cap on SO_2 emissions on a ton per day basis. Emissions are calculated from all emission points daily. This limit is 0.31 tons SO_2 per day.

This condition includes the same definition of "day" as both of the previous conditions as being from midnight until the following midnight. Compliance 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. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.2.f.iv This condition addresses specific fuel sulfur requirements for the refinery, allowing the use of diesel-fired emergency equipment as an exception to IX.H.1.g.iv.

Holly currently has a number of small diesel-fired emergency engines listed in its AO. No specific provision has ever been made to allow for the use of diesel-fired emergency equipment at the refineries – and while it is clear that the provisions of 2.a.M.A$^{\{OS\}}$ were meant for the burning of liquid fuel in heaters and boilers and not for the application of emergency equipment, such language was not included nor brought forward. This condition (and similar conditions for the other refineries) addresses that oversight.

6.1 Monitoring, Recordkeeping and Reporting

Monitoring for all three conditions is addressed through a variety of methods, depending on the emission point in question. Stack testing, CEMs, parameter monitoring – all are viable options, and have been included in the language of IX.H.2.f.i through IX.H.2.f.iii. As appropriate, these monitoring requirements are complemented by the general provisions of IX.H: 1.e for stack testing, 1.f for CEMs and other continuous monitors, 1.c for recordkeeping and reporting.

Where necessary, additional monitoring, recordkeeping and/or reporting requirements have been directly included in the language of IX.H.2.f to address specific concerns. One example would be

the use of leveling gauges on all fuel oil tanks to determine daily fuel oil consumption.

No specific monitoring, recordkeeping or reporting is required for IX.H.2.f.iv, as this condition serves merely as a specific exception to the general refinery requirement prohibiting the burning of liquid fuel oils. Such exception is authorized under the language of IX.H.1.g.iv itself.

Flare gas monitoring requirements – under subsection IX.H.11.g.v.B of the PM2.5 SIP, each refinery, including Holly, is required to install and operate a flare gas recovery system or equivalent flare gas minimization process. This system needs to limit hydrocarbon flaring below 14,160 standard cubic meters (m3) (500,000 standard cubic feet (scf)) above the baseline established by the procedure outlined in 40 CFR 60.103a(a)(4). As the specific requirements of IX.H.11.g.v.B were not brought forward into the new maintenance plan, each refinery is required to include monitoring for flare gas such that total flare gas flow rate can be recorded on a daily basis, the daily flare gas recovered for fuel gas processing can be recorded, and an estimate of daily flare gas emissions can be made. All flaring emissions are included in the daily emission Caps, and monitoring of flare gas flows satisfies both the requirements of demonstrating compliance with the daily Caps as well as subsection IX.H.11.g.v.B.

6.2 Discussion of Attainment Demonstration

Generally, the calculation methodology for determination of daily (24-hr) source-wide emissions from the Holly refinery is identical to the method used in during the 1991/1992 timeframe of the original SIP. However, several key differences exist:

1. Emissions in the new maintenance plan are lower than in the original SIP

As is shown above in Table 3, the daily SIP Caps have dropped for all pollutants of concern [PM_{10}, SO_2 and NO_x]. The annual emissions have also dropped for all pollutants, although no annual Cap is required.

2. All emission units/emission points are included in the new maintenance plan

The original SIP was based on a concept of "SIP Cap sources", where only certain specific sources were included as contributing toward the emission total for a particular pollutant. Other sources, such as the flares or the compressors, would be specifically excluded from counting towards this total. This would even be spelled out by a specific requirement in the original SIP. The new maintenance plan eliminates this concept by simply stating that all sources are included, and that the emission "Caps" apply source-wide.

3. Condensable emissions, which were excluded from the original SIP, are included in the new maintenance plan

The original SIP was based on filterable PM_{10} emissions only. The new maintenance plan includes both filterable and condensable PM_{10} emissions. The 24-hour source-wide PM_{10} limit listed in IX.H.2.f.i clearly states that condensable emissions are included from all sources, and the emission factors listed in that condition include values for condensable emissions.

7.0 Interim Emission Limits and Operating Practices

When the new maintenance plan is issued and made effective, the existing SIP Sections IX.H.1-4 will be repealed and replaced. On a federal level, the currently approved 1991 PM10 State

Implementation Plan will be superseded with the newest version. As many of the requirements and emission limits in IX.H.1 and IX.H.2 for the refineries have implementation dates of January 1, 2018 or January 1, 2019, an "implementation gap" could have potentially existed between the effective date of the SIP and those future compliance dates.

In order to address this concern, new Subsection IX.H.4, titled Interim Emission Limits and Operating Practices has been established to serve as a bridge between these two periods. For all other point sources listed in IX.H.2 and IX.H.3 the limits apply upon approval by the Utah Air Quality Board of the PM_{10} Maintenance Plan.

There are two main sections of IX.H.4: a set of general requirements that applies to all petroleum refineries in or affecting any PM10 nonattainment/maintenance area, and then a set of specific requirements for each of the four listed refineries in IX.H.2 (BWO, Chevron, Holly and Tesoro). Both the general and specific requirements of IX.H.4 are designed to be used in conjunction with all of the requirements of IX.H.1. As these limits and operating practices are to serve only during the brief period between SIP issuance and January 1, 2019, only a bare minimum of requirements were retained. All requirements are specifically pulled from each source's latest AO, such that the source will continue to remain in compliance; however, each requirement also matches the 2005 State-only SIP. As the control technology for the sources listed in this subsection is installed and operational, the terms and conditions listed in IX.H.1 and IX.H.2 becomes applicable and those limits then replace the limits in this subsection.

For Holly the following conditions and limitations apply during the interim period:

A. Refinery General – retention of the 9.8 kg of SO2 per 1,000 kg of coke burn-off from any Catalytic Cracking unit limit.
B. Combined emissions of filterable PM10 from all combustion sources, shall be no greater than 0.44 tons per day.
C. Combined emissions of SO2 from all sources shall be no greater than 4.714 tons per day.
D. Combined emissions of NOx from all sources shall be no greater than 2.20 tons per day.

Each limit has an associated compliance demonstration method and averaging period.

8.0 Implementation Schedule

The daily (24-hour) emission Caps are effective as of January 1, 2019. This schedule is dictated by the original RACT requirements established under the $PM_{2.5}$ SIP of 2014 (IX.H.11-13). In order to allow for construction, installation, shakedown and initial testing of the new equipment, this January 1, 2019 date was selected. Demonstration of attainment under the new PM_{10} maintenance plan is also set as January 1, 2019.

The provisions of IX.H.1.a-f (the General Requirements) are effective immediately upon implementation of the new maintenance plan. Those listed in IX.H.1.g (Refineries) have variable implementation dates depending on the specific provision. Some take effect immediately, while others take effect on January 1, 2018 or on January 1, 2019. Again, these dates exactly match those listed in the $PM_{2.5}$ section of the SIP (IX.H.11).

In order to address the possibility of an "implementation gap" from occurring, interim emission limits and operating practices have been established. These interim requirements are found in Subsection IX.H.4 of the new maintenance plan. For complete details on these requirements, please see Item 7.0 above.

9.0 References

Evaluation Report – Holly Refinery

UTAH PM_{10} SIP/MAINTENANCE PLAN

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report:
Kennecott Utah Copper – Bingham Canyon Mine & Copperton Concentrator

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
Bingham Canyon Mine and Copperton Concentrator

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the PM_{10} Maintenance Plan (Maintenance Plan); to address the Salt Lake County PM_{10} Nonattainment Area. This document specifically serves as an evaluation of Kennecott Utah Copper's Bingham Canyon Mine and Copperton Concentrator.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Section IX.H of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report.
- When referencing the original SIP (the one issued in 1991/1992 and adopted by EPA in 1994), the qualifier $^{\{OS\}}$ will follow any citation from that document.
- When referencing any new SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Kennecott Utah Copper Bingham Canyon Mine and Copperton Concentrator
Address: 8362 West 10200 South, Bingham Canyon, Utah, Salt Lake County
Owner/Operator: Kennecott Utah Copper, LLC
UTM coordinates: 407,000m Easting, 4,493,000 m Northing, Zone 12

1.2 Facility Process Summary

Kennecott Utah Copper operates the Bingham Canyon Mine and Copperton Concentrator in Salt Lake County, Utah. The Bingham Canyon Mine is an open pit copper mine. Ore is mined by drilling, blasting, crushing and hauling. The Copperton Concentrator receives ore material from

the Bingham Canyon Mine. At the Concentrator, ore is crushed and turned into slurry concentrate in the floatation process.

1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of installations at the Bingham Canyon Mine:

- In-pit crushers with baghouses
- Roadbase crushing units
- Conveyors and transfer points with baghouses
- Emergency generators
- Concrete batch plant controlled by baghouse
- Crushers and screens
- Haul trucks
- Support equipment

The following is a listing of installations at the Copperton Concentrator:

- Feed dryer oil heater
- Product dryer oil heater
- Molybdenite storage bins
- Molybdenite loading facility
- Ore sorting and sample preparation baghouses

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at the Bingham Canyon Mine and Copperton Concentrator, rather it is a listing of all significant emission units.

1.4 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, the Bingham Canyon Mine and Copperton Concentrator baseline actual emissions were determined to be the following (in tons per year):

Table 1A: Actual Emissions Bingham Canyon Mine

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	808
SO_2	3.0
NO_x	3552

Table 1B: Actual Emissions Copperton Concentrator

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	1.94
SO_2	0.004
NO_x	0.67

Since 2011, the BCM has expanded operations and updated emissions calculation methodology. The Copperton Concentrator has also made modifications to the plant. The current PTE values, as established by the most recent AOs at the mine and concentrator (DAQE-AN105710036-14 and DAQE-AN105710035-13, respectively), are as follows:

Table 2A: Current Potential to Emit Bingham Canyon Mine

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	1,513
SO_2	7
NO_x	5,830

Table 2B: Current Potential to Emit Copperton Concentrator

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	25.3
SO_2	0.10
NO_x	10.66

2.0 Demonstration of Maintaining Attainment

These values have been used in the modeled attainment demonstration. The 2011 actual emissions were used as baseline for model validation. The Copperton Concentrator emissions were projected for future years using growth factors for the mining industry in Salt Lake County. Those emissions projected with growth are intended to represent future actual emissions for the Copperton Concentrator. The Bingham Canyon Mine differed from most of the listed sources in the establishment of projection year inventories. Rather than using a combination of "true-up" 2019 actual emissions plus projection year growth values, DAQ instead applied the facility's emissions based on daily mine activity as the 2019 true-up value, and then assigned a growth factor of zero (0) to each of the projection years.

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent PM2.5 Section of the SIP. This Section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM10 SIP. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11, IX.H.12 and IX.H.13 – which comprise the PM2.5 sections of the SIP, and include this additional RACT application. All requirements from the original PM10 SIP that have not been superseded or replaced, and which are still necessary will also be retained. By necessary, meaning: needed in the demonstration of attainment of the 24-hour standard, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

The Bingham Canyon Mine and Copperton Concentrator are previously listed SIP sources. In the original PM_{10} SIP document for Davis and Salt Lake Counties [IX.H.2 Emission Limitations and Operating Practices (Davis and Salt Lake Counties) – dated 28 June 1991 and Updated 4 November 1992]$^{\{OS\}}$, the Bingham Canyon Mine was listed in Subsection IX.H.2.b.W$^{\{OS\}}$ and Copperton Concentrator was listed in Subsection IX.H.2.b.X$^{\{OS\}}$. As listed sources there were several requirements and conditions that applied to the facility.

In addition, the Bingham Canyon Mine is a listed source in the PM2.5 Section of the SIP (see SIP Section IX.H.12.l.i). The Copperton Concentrator is not a listed source in the PM2.5 Section of the SIP. As was discussed above in Item 2.0, the limits in this maintenance plan are based on the limits in the PM2.5 SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12. Therefore, a comparison between the original SIP

requirements, and those found in this new maintenance plan can be found below:

3.1 Original SIP General Requirements

IX.H.2.a General Requirements{OS}

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a{OS} applied to the listed sources found in Utah County, while those found at IX.H.2.a{OS} applied to the listed sources found in Salt Lake and Davis Counties. The Bingham Canyon Mine and Copperton Concentrator are located in Salt Lake County, only the general requirements of IX.H.2.a{OS} applied. However, except for the additional requirements found under IX.H.2.a.M{OS} for petroleum refineries and the specific fuel requirements of IX.H.2.a.N{OS}, the two subsections are essentially identical.

2.a.A. Stack Testing{OS} – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which incorporates equivalent language.

2.a.B. Visible Emissions{OS} – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.C. Visible Emissions (cont.){OS} – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.D. Annual Emission Limitations{OS} – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists.

2.a.E. Recordkeeping Requirements{OS} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders{OS} – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance{OS} – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program.

2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program.

2a.I. Unpaved Operational Areas{OS} – established rules for treating fugitive dust with water sprays or chemical dust suppression.

2.a.J. Actual Emissions{OS} – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsection IX.H of the SIP. This requirement is outdated and obsolete.

2.a.K. Test if Directed{OS} – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions{OS} – established that the definitions contained in R307 apply to Section IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.M. Petroleum Refineries{OS} – This is a fairly lengthy subsection pertaining only to the petroleum refineries. This subsection has its own sub-subsections that are either moved or no longer necessary.

2.a.N. Specific Fuel Requirements for Coal and/or Oil{OS} – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded by the individual source requirements found in IX.H.2 and IX.H.3. This requirement is now, largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources located at the Bingham Canyon Mine or the Copperton Concentrator burn coal. Sources at the mine and concentrator meet the requirements of sulfur content allowed in diesel fuel.

3.2 Original SIP Source Specific Requirements

Individual source requirements for the Bingham Canyon Mine:

2.b.W.1.{OS} This subsection was a listing of the equipment at the mine and concentrator – this subsection has been superseded and is irrelevant. A simple listing of equipment does not constitute an emission limitation, does not impose any restriction on daily emissions, and rapidly becomes out of date as well as impossible to enforce.. The original listing found in this subsection does not match the current equipment installed and operating and would represent a significant step backwards in emission control and technology.

2.b.W.2.{OS} This subsection includes a 12-month limit on total material moved and specifies the approval process to exceed the limit. In accordance with this condition, two approval orders were issued– the first one in 1999 and the second one in 2011 – allowing an increase in the amount of material moved per 12-month period.

This limit is an annual limit. The PM_{10} annual standard was revoked in 2006 and the primary and secondary standard for PM_{10} is now a 24-hour standard. To protect the 24-hour standard, the limit on daily haul truck mileage was established in the PM_{10} SIP. This is now in the current PM_{10} SIP subsection IX.H.12.l.i.A. This condition enforces the daily vehicle miles limitation with monitoring and record keeping requirements for the miles travelled by ore and waste haul trucks. Daily records shall be kept for all periods when the mine is in operation and haul truck

miles shall be tracked with a Global Positioning System or equivalent.

2.b.W.3.,7-8.{OS} These subsections established visible emissions limits and test methods. Visible emissions limits and opacity observation requirements are more viable in the general requirements of the SIP. Visible emissions limits are consistent with federal standards set in 40 CFR Part 60 Subpart LL (Standards of Performance for Metallic Mineral Processing Plants). Section 60.382 sets the opacity for the processing plants at 7% for controlled emission points and 10% for all other points.

2.b.W.4.{OS} This subsection established emissions limitations for baghouse vents and conveyor transfer points. This subsection is outdated and some equipment has been removed and the others have since been updated to reflect current operations and BACT. Some of the limits have been changed since 1994 and the stack test results are less than the limits. The In-Pit Crusher limit was 1.77 lbs/hr and 0.016 grains/dscf. The lb/hr limit of 1.77 lb/hr has been retained but the 0.016 gr/dscf has been replaced with the NSPS Subpart L limit of 0.05 gram/dscm and the limits are listed in IX.H.2.g.i.C.

The two drop point baghouses are limited at 0.22 lbs/hr (0.016 grains/dscf) in the 1994 SIP. They have been modified and in 1999 AO DAQE-441-99 set the limits at 0.70 lb/hr for drop point C6/C7 located at the tunnel exit near Copperton at 0.70 lbs/hr, and 0.43 lbs/hr for the drop point at Copperton (C7/C8). The 1999 AO increased the material moved from 150,500,000 to 197,000,000 tons per year. These emission increases were offset with the emissions banked by KUC from the 1994 SIP emission limits. In 2011 KUC upgraded the C6/C7 AND C7/C8 baghouses and the limits were set at 0.31 lb/hr with 0.016 gr/dscf (C6/C7) and 0.19 lb/hr with 0.016 gr/dscf (C7/C8). The two baghouses were tested in 2013 at 0.03 lbs/hr (C6/C7), and 0.02 lbs/hr (C7/C8). If these two baghouses operated for 8760 hrs, the combined emission rate would only be 0.22 tpy. Based on these results and the fact that they both have been modified to a lower emission rate, this requirement is outdated and is no longer needed to demonstrate compliance with the PM_{10} standard.

2.b.W.5.{OS} Stack Testing Requirements – established test method to be used to verify compliance and the frequency of testing. This subsection has since been superseded by SIP subsections IX.H.2.g.C.II and IX.H.1.a General Requirements - Stack Testing.

2.b.W.6.{OS} This subsection specifies a maximum waste dump lift height. Waste dump lift height is established to meet structural and geotechnical requirements. Height of the lift is not related to particulate emissions and currently KUC does not dump on the South Slope. The mine no longer constructs dumps in 1000 foot lifts due to geotechnical reasons. The current process for dump design and construction is based on geotechnical and operational parameters. Lift heights vary based on parameters such as dump geometry, dump capacity and foundational conditions below the dump. Currently they dump the waste material in the Bingham Canyon area and in lifts that are less than the previous 10000 ft dump. When they continue on the South Slope, it will be in lifts which will be less than the 1000 ft drop utilized in the past.

2.b.W.9.{OS} This subsection specifies fugitive dust control requirements for roads. This subsection is superseded by general condition in SIP subsection IX.H.1.h and source specific requirements in SIP subsection IX.H.2.g.i.D and IX.H.2.g.i.E.

2.b.W.10.{OS} This subsection includes operations limitations for mine operations. This subsection has been superseded by daily limitations in SIP subsection IX.H.2.g.i. Monitoring and record keeping requirements for a daily limitation of 30,000 miles travelled by ore and waste haul trucks

will be included in the new maintenance plan. Daily records shall be kept for all periods when the mine is in operation and haul truck miles shall be tracked with a Global Positioning System or equivalent. It is to KUC's benefit to use larger trucks. If they used smaller trucks then they would reach the 30,000 mile daily limit sooner without reaching their production levels needed. Currently their AO DAQE-AN105710036-14 requires KUC 240 tons for ore and waste haul trucks and 40 tons for underground usage. As KUC develops their underground mining they will not be able to use the larger trucks and will need to use the smaller trucks (40 tons) This requirement is outdated and their emissions are more limited by the mileage than by the truck size..

2.b.W.11.{OS} This subsection establishes a drilling method to reduce particulate emissions. The method is inherent in how the mine conducts drilling operations. The 2011 actual emissions from the wet drilling were 0.48 tpy PM_{10}. Wet drilling is a requirement of the operations which makes this subsection outdated and no longer needed to demonstrate attainment and to prevent backsliding. Since the emissions from these sources are minimal, a source specific condition in the SIP is not warranted.

2.b.W.12.{OS} This subsection establishes particulate control for lime silos. The lime silos are equipped with bin vent control units which are BACT for this type of emission units. Minimal emissions are emitted from the lime silos (0.039 tpy PM_{10} in 2011). The emissions are included in the appropriate SIP modeling. Since the emissions from these sources are minimal, a source specific condition in the SIP is not warranted. This subsection outdated and no longer needed to demonstrate attainment and to prevent backsliding.

2.b.W.13.{OS} This subsection establishes measures for spraying storage piles with water or chemical suppressants. This requirement provides control of material that has been evacuated. This requirement has been retained in IX.H.1.g.i.F.

2.b.W.14.{OS} This subsection limits sulfur content in diesel fuel. Federal rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. Sulfur content is this subsection is outdated. Emissions from off-road equipment are now estimated by EPA's NONROAD program and this subsection is outdated and superseded by the requirement to use ultra-low sulfur fule in their haul trucks in SIP subsection IX.H.2.g.i.C.

2.b.W.15.-16.{OS} These subsections reference New Source Performance Standards and testing methods. Compliance with federal NSPS requirements is required by sources and the testing methods specified are outdated. Federal standards and testing methods are not needed in the individual source sections of the SIP.

2.b.W.17.{OS} This subsection requires facilities to be properly maintained. Subsection 2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program, under UAC R307-401-3(1)(b), Applicability to NSR, and UAC R307-401-4, General Requirements.

2.b.W.18. & 2.b.X.14.{OS} Annual Emissions – established total annual emissions estimates for the entire Bingham Canyon Mine. Annual emissions estimates for the mine and concentrator are based on estimation methodologies as of 1991. Current PTE estimates (Section 1.4 of this document) are based on improved emissions methodologies including BACT. Conditions

limiting daily activity, included in SIP subsection IX.H.2.g.i, supersede the outdated annual emissions estimates. Therefore, the annual emission estimates have been eliminated.

Individual source requirements for the Copperton Concentrator:

2.b.X.1{OS} This subsections was a listing of the equipment at the concentrator – this subsection has been superseded and is irrelevant. A simple listing of equipment does not constitute an emission limitation, does not impose any restriction on daily emissions, and rapidly becomes out of date as well as impossible to enforce. The original listing found in this subsection does not match the current equipment installed and operating and would represent a significant step backwards in emission control and technology.

2.b.X.2.&3.{OS} These subsections established visible emissions limits and test methods. Visible emissions limits and opacity observation requirements are more viable in the general requirements of the SIP. Visible emissions limits are consistent with federal standards and are superseded by SIP subsection IX.H.1.f and the UAC R307-309, Nonattainment and Maintenance Areas for PM_{10} and $PM_{2.5}$: Fugitive Emissions and Fugitive Dust.

2.b.X.4.{OS} These subsections reference New Source Performance Standards and testing methods. Compliance with federal NSPS requirements is required by sources and the testing methods specified are outdated. Federal standards and testing methods are not needed in the individual source sections of the SIP.

2.b.X.5.{OS} This subsection requires facilities to be properly maintained. Subsection 2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. This is inherent in the NSR permitting program, under UAC R307-401-3(1)(b), Applicability to NSR, and UAC R307-401-4, General Requirements. Therefore, this requirement is not needed to enforce compliance with the limiting emissions from a source.

2.b.X.6.{OS} This subsection requires scrubber monitoring per federal standards. Federal standards and testing methods are not needed in the individual source section of the SIP.

2.b.X.7.{OS} This subsections established emissions limitations. This subsection is outdated and some equipment has been removed and the others have since been updated to reflect current operations and BACT. Emissions for the Copperton facility in 2011 were 1.94 tpy for PM_{10} and 0.004 tpy for SO_2. In 2005 KUC removed the Feed Molybdenite Dryers and the Molybdenite Heat Treater, and replaced a Product Molybdenite Dryer. Emissions from the Product Molybdenite dryers are 0.15 lb/hr or 0.66 tpy if operated 8,760 hours per year. The Molybdenite Storage Bins have an emission rate of 0.21 lbs/hr (0.92 tpy) and the loading facilities have an emission rate 0.07 lbs/hr (0.31 tpy). These emissions are insignificant and testing is not required to demonstrate attainment and to prevent backsliding.

2.b.X.8.{OS} Stack Testing Requirements – established test method to be used to verify compliance and the frequency of testing. The limits have been removed and this subsection is no longer required.

2.b.X.9.{OS} This subsection includes the requirement for natural gas and LPG use as a fuel source unless an Approval Order allows another fuel. Natural gas and LPG combustion sources exist at the Copperton Concentrator. If another fuel is proposed an Approval Order modification would be necessary and a BACT analysis would demonstrate that another fuel such as fuel oil would not

meet the BACT requirements. This subsection is outdated and is no longer needed.

2.b.X.11.&13{OS} The process listed in this subsection no longer exists at the Copperton Concentrator. This subsection is outdated and is no longer needed.

2.b.X.12.{OS} This subsection established 30-day limits on natural gas consumption for combustion sources. This subsection is outdated and some equipment has been removed and the others have since been updated to reflect current operations and BACT. The emissions in 2011 for the Copperton facility was 0.67 tpy for NO_x. This emission rate is insignificant and a fuel limit is not required to demonstrate attainment and to prevent backsliding. This subsection is no longer needed in regulating daily activity.

2.b.W.18. & 2.b.X.14.{OS} Annual emissions estimates for the mine and concentrator are based on estimation methodologies as of 1991. Current PTE estimates (Section 1.4 of this document) are based on improved emissions methodologies including BACT. Conditions limiting daily activity, included in SIP subsection IX.H.12.l.i, supersede the outdated annual emissions estimates.

2.b.X.14.{OS} Annual Emissions – established total annual emission estimates for the entire Copperton Concentrator facility. The PM_{10} annual standard has been eliminated and these estimates are annual estimates. Salt Lake County has not shown an exceedance in over ten years and the reduction in allowable emissions will demonstrate a prevention of backsliding. Therefore, the annual emission estimates have been eliminated.

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including

periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as

a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan Specific Requirements

The Bingham Canyon Mine and Copperton Concentrator specific conditions in Section IX.H.2.g address those limitations and requirements that apply to the mine and concentrator.

IX.H. 2.g.i.A Maximum total mileage per calendar day for ore and waste haul trucks shall not exceed 30,000 miles.

KUC shall keep records of daily total mileage for all periods when the mine is in operation. KUC shall track haul truck miles with a Global Positioning System or equivalent.

This condition establishes a limitation on daily activity. The daily mileage limitation effectively limits road dust emissions, tailpipe emissions from the haul trucks and overall activity of sources at the mine. Ore processing at the Copperton Concentrator, which results in minimal emissions, is also limited through the Bingham Canyon Mine activity limitations.

Emissions for the Bingham Canyon Mine are estimated using the most current calculation methodology. Daily emissions from the Bingham Canyon Mine can be regulated with the limitation on vehicle miles traveled by ore and waste haul trucks of 30,000 miles per day. Compliance to this limitation is demonstrated on a daily basis and is an appropriate metric for a 24-hour particulate standard.

Emissions resulting from the movement of ore and waste around the mine represent a significant portion of overall emissions at the Bingham Canyon Mine. The emissions related to material movement include fugitive dust generated from the truck travel on the haul roads and the tailpipe emissions from the haul trucks. Specifically, on an annual basis, greater than 99.9 percent of total mine emissions for NOX and SO2 come from the haul truck tailpipes. Also on an annual basis, material movement represents 85% or greater of overall particulate emissions at the Bingham Canyon Mine. Based on these emissions, the material movement of ore and waste by haul trucks represents a vast majority of overall emissions at the Bingham Canyon Mine and can effectively be used to represent mine operations.

It should be noted that the 30,000 miles per day limitation also limits overall Bingham Canyon Mine operations. Ancillary mining activities such as operation of the in-pit crusher, blasting, and drilling only occur to produce adequate amount of ore and waste rock that can be hauled via the trucks and sent to the concentrator via the conveyor system.

KUC uses conveyors as a primary means of crushed ore transport from the mine to the Copperton Concentrator. The use of conveyor as a primary means of transport reduces both fugitive dust and tailpipe emissions to the atmosphere. If KUC were to use haul trucks as a primary means to move crushed ore to the Copperton Concentrator, the daily mileage limit would be easily exceeded. Therefore, in order to comply with the daily mileage limit, KUC would have to use conveyors as

a primary means to transport ore to the Copperton Concentrator.

On a 24-hour basis, these emissions can be represented with a 30,000 miles per day limitation. Since they effectively represent mine operations, a single daily limitation is appropriate in the SIP for the Bingham Canyon Mine. These emissions have been included in the appropriate SIP model so emission caps are therefore not warranted.

The PTE emissions from the mine were used in the modeling that showed attainment with the PM_{10} standard. The combined emissions from the mine are 24.79 tons per day (tpd) (19.86 tpd NO_x, 4.62 tpd PM_{10} and 0.32 tpd SO_2). The PM_{10} emissions from the haul roads are 2.65 tpd using a pit escape factor of 20% (7.04 without factor). The NO_x emissions are 19.86 tpd from the mobile sourcs.

IX.H.2.l.i.B KUC shall use ultra-low sulfur diesel fuel in ore and waste haul trucks.

This condition establishes a requirement for the use of ultra-low sulfur diesel fuel in haul trucks.

IX.H.2.l.i.C This condition limits the Emissions from the In-pit Crusher baghouse. The lb/hr limits are from the 1994 SIP while the concentration limit is from 40 CFR Part 60 Subpart LL (Standards of Performance for Metallic Mineral Processing Plants).

IX.H.2.l.i.D This condition establishes requirements for reducing and controlling fugitive particulate emissions at the mine and concentrator. Ore conveyors shall be the primary means for transporting ore from the mine to the concentrator thereby displacing truck traffic. Water and chemical dust suppressants shall be used to minimize fugitive dust on haul roads and access roads.

KUC has implemented a comprehensive fugitive dust management program at the Bingham Canyon Mine to minimize fugitive emissions. These practices represent Best Available Control Technology (BACT) and in many cases result in controls beyond BACT. These practices are inherent to the operations at the mine and result from the most recent BACT analysis for emission sources at the mine. Implementation of aggressive dust control practices is also necessary at the Bingham Canyon Mine to meet the requirements of both the Approval Order and other limitations in the State Implementation Plans. This requirement originated in the 1994 PM_{10} SIP.

IX.H.2.l.i.E KUC is subject to the fugitive dust rules that are in R307-1-4.5, Fugitive Emissoins and Fugitive Dust. This rule was approved by EPA in 1994 and is applicable to the BCM under the 1994 PM_{10} SIP. This rule sets a minimum for controlling fugitive dust at mines located in the nonattainment area along the Wasatch Front. The subsection R307-1.4.5.4, Mining Activities, outlines the minimum requirements that mines are to follow in minimizing the fugitive dust from the mining operations.

5.1 Monitoring, Recordkeeping and Reporting

Monitoring, recordkeeping and reporting for all three conditions is addressed through a variety of methods, depending on the emission points. Haul truck miles shall be tracked with a global positioning system or equivalent and records of daily total mileage shall be kept for all periods when the mine is in operation. Fuel delivery records and records of road dust mitigation measures shall be kept in accordance with SIP subsection H.11.c.

5.2 Discussion of Attainment Demonstration

Generally, the calculation methodology for determination of emissions from the Bingham Canyon Mine and Copperton Concentrator is similar to the method used in during the 1991/1992 timeframe of the original SIP. However, two key differences exist:

1. Updated emissions estimation methodologies.

As mentioned in the source specific conditions section of this document, emissions estimation methodology has been updated for tailpipe emissions from off-road engines. Tailpipe emissions from haul trucks and support equipment at the mine are estimated using EPA's NONROAD program based on engine size and tier rating.

2. Condensable emissions, which were excluded from the original SIP, are included in the new maintenance plan

The original SIP was based on filterable PM_{10} emissions only. The new maintenance plan modeled both filterable and condensable PM_{10} emissions.

6.0 Implementation Schedule

The requirements imposed on the BCM are effective immediately, except for the requirement for higher tiered haul trucks. In accordance with the PM2.5 RACT analysis, the haul truck engines will be replaced with higher tier engines on a replacement schedule. The general requirements, IX.H.1.a-f, can be applied immediately.

7.0 References

- Bingham Canyon Mine, $PM_{2.5}$ SIP Major Point Source RACT Documentation
- Copperton Concentrator, $PM_{2.5}$ SIP Major Point Source RACT Documentation
- UDSHW Contract No. 12601, Work Assignment No. 7, Utah $PM_{2.5}$ SIP RACT Support – TechLaw Inc.
- Bingham Canyon Mine Approval Order DAQE-AN105710036-14
- Copperton Concentrator Approval Order DAQE-AN105710035-13
- Bingham Canyon Mine In Pit Crusher 2012 stack test results
- Bingham Canyon Mine 2013 stack test results for the two conveyor crushers
- Utah Administrative Code R307-1-4.5.

Evaluation Report

UTAH PM_{10} SIP/MAINTENANCE PLAN

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report: Kennecott Utah Copper - Power Plant

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
Power Plant

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the Utah PM_{10} Maintenance Plan; to address the Salt Lake County PM_{10} Nonattainment Area. This document specifically serves as an evaluation of the Kennecott Utah Copper (KUC) Power Plant located in Salt Lake County.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Section IX.H of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report.
- When referencing the original SIP (the one issued in 1991/1992 and adopted by EPA in 1994), the qualifier $^{\{OS\}}$ will follow any citation from that document.
- When referencing any new SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Kennecott Utah Copper Power Plant
Address: 9600 West 2100 South, Magna, Utah, Salt Lake County
Owner/Operator: Kennecott Utah Copper, LLC
UTM coordinates: 4,507,000 m Northing, 405,000 m Easting, Zone 12

1.2 Facility Process Summary

Kennecott Utah Copper operates a Power Plant. The Power Plant is a four-unit, 175-megawatt capacity steam turbine generator facility. The initial plant was constructed in 1943, with the

current output capacity and configuration since 1959. The plant operates on both coal and natural gas. In 2011 KUC received a permit to install a new combined-cycle, natural gas-fired combustion turbine. It will replace three existing coal-fired boilers (identified as Units 1, 2 and 3 boilers). The emissions will be limited through a combination of dry low-NOx combustors, selective catalytic reduction (SCR) and catalytic oxidation (CatOx).

1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of the main emitting units from the KUC Power Plant:

- Power Plant Boiler #1
- Power Plant Boiler #2
- Power Plant Boiler #3
- Power Plant Boiler #4
- Power Plant Turbine (Unit #5)
- Hot Water Boiler
- Cold Solvent Parts Washers
- Wet Cooling Towers
- Natural Gas Generator
- Hydraulic Coal Unloader System with Diesel Engine
- Coal and Ash Handling Equipment
- Diesel Engine

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at the power plant, rather it is a listing of all significant emission units or emission unit groups.

1.4 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, the power plant baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	43.93
SO_2	1,704.17
NO_x	920.18

The actual emissions are from the 2011 inventory. The current PTE values for the KUC power plant, as established by the most recent AO issued to the source (DAQE-AN105720026-11) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	256.00
SO_2	6,522
NO_x	4,160

2.0 Demonstration of Maintaining Attainment

These values have been used in the modeled attainment demonstration. The 2011 actual emissions were used as baseline for model validation. The power plant emissions were projected for future years using growth factors for the manufacturing industry in Salt Lake County. Those emissions projected with growth are intended to represent future actual emissions for the power plant.

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent PM2.5 Section of the SIP. This Section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM10 SIP sources – including the KUC Power Plant in specific. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11, IX.H.12 and IX.H.13 – which comprise the PM2.5 sections of the SIP, and include this additional RACT application. All requirements from the original PM10 SIP that have not been superseded or replaced, and which are still necessary will also be retained. By necessary, meaning: needed in the demonstration of attainment of the 24-hour standard, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

The Kennecott Power Plant is a previously listed SIP source. In the original PM_{10} SIP document for Davis and Salt Lake Counties [IX.H.2 Emission Limitations and Operating Practices (Davis and Salt Lake Counties) – dated 28 June 1991 and Updated 4 November 1992]$^{\{OS\}}$, the power plant was listed in Subsection IX.H.2.b.Z$^{\{OS\}}$ as Kennecott Utah Copper, Utah Power Plant. As a listed source there were several requirements and conditions that applied to the facility.

In addition, the power plant is also a listed source in the $PM_{2.5}$ Section of the SIP (see SIP Section IX.H.12.n.i). As was discussed above in Item 2.0, all limits in this maintenance plan are based on the limits in the $PM_{2.5}$ SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.n.i. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below:

3.1 Original SIP General Requirements

IX.H.2.a General Requirements$^{\{OS\}}$

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a$^{\{OS\}}$ applied to the listed sources found in Utah County, while those found at IX.H.2.a$^{\{OS\}}$ applied to the listed sources found in Salt Lake and Davis Counties. As the then the power plant was located in Salt Lake County, only the general requirements of IX.H.2.a$^{\{OS\}}$ applied. However, except for the additional requirements found under IX.H.2.a.M$^{\{OS\}}$ for petroleum refineries and the specific fuel requirements of IX.H.2.a.N$^{\{OS\}}$, the two subsections are essentially identical.

2.a.A. Stack Testing$^{\{OS\}}$ – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which incorporates equivalent language.

2.a.B. Visible Emissions{OS} – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.C. Visible Emissions (cont.){OS} – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.D. Annual Emission Limitations{OS} – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists.

2.a.E. Recordkeeping Requirements{OS} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders{OS} – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance{OS} – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program.

2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program.

2a.I. Unpaved Operational Areas{OS} – established rules for treating fugitive dust with water sprays or chemical dust suppression.

2.a.J. Actual Emissions{OS} – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsection IX.H of the SIP. This requirement is outdated and obsolete.

2.a.K. Test if Directed{OS} – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions{OS} – established that the definitions contained in R307 apply to Section IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.M. Petroleum Refineries{OS} – This is a fairly lengthy subsection pertaining only to the petroleum refineries. This subsection has its own sub-subsections that are either moved or no longer necessary.

2.a.N. Specific Fuel Requirements for Coal and/or Oil{OS} – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded by the individual source requirements found in IX.H.2 and IX.H.3 (see specifically the sources Kennecott and BYU). This requirement is now, largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources have the ability to burn any other fuel oils.

3.2 Original SIP Source Specific Requirements

KUC is in the process of upgrading their power plant with the removal of Units 1, 2 & 3 by January 2018. KUC will also be upgrading Unit 4 with low NO_x burners by January 2018.

Individual source requirements:

2.b.Z.1.{OS} This subsection was a listing of the equipment at the power plant – this subsection has been superseded and is irrelevant. A simple listing of equipment does not constitute an emission limitation, does not impose any restriction on daily emissions, and rapidly becomes out of date as well as impossible to enforce. The original listing found in this subsection will be replaced and would represent a significant step backwards in emission control.

2.b.Z.2.{OS} This subsection sets fuel requirements, emission limits and testing frequencies for Units 1-4 during the winter months from November 1 to the last day of February. These requirements are inherent to the ongoing operations at the Utah Power Plant and will be superseded by requirements in IX.H.2.h.i.D.II.

2.b.Z.3.{OS} This subsection sets fuel requirements and emission limits for the Units 1-4 during the non-winter months from March 1 to October 31. These requirements are inherent to the ongoing operations at the Utah Power Plant and will be superseded by requirements in IX.H.2.h.i.D.III.

2.b.Z.4.{OS} This subsection sets testing frequencies for the limits set in condition 2.b.Z.3, above. These requirements are inherent to the ongoing operations at the Utah Power Plant and will be superseded by requirements in IX.H.2.h.i.D.IV.

2.b.Z.5.{OS} This subsection sets opacity limits for Units 1-4. Visible emissions limits are consistent with federal standards and will be superseded by requirements in Section IX.H.1.f.

2.b.Z.6.{OS} This subsection limits sulfur content in fuel and reporting requirements for Units 1-4. These requirements are inherent to the ongoing operations at the Utah Power Plant and are not needed in the source specific limitations section of the Maintenance Plan.

2.b.Z.7.{OS} This subsection sets monitoring requirements for fuel consumption in Units 1-4. These requirements are inherent to the ongoing operations at the Utah Power Plant and are not needed.

2.b.Z.8.{OS} Annual Emissions – established total annual emissions for the entire power plant. Conditions limiting operations of the boilers included in Maintenance Plan Section IX.H.2.h.i.D supersede the outdated annual emissions estimates. Therefore, the annual limits have been eliminated. Salt Lake County has not shown an exceedance in over ten years and the reduction in

allowable emissions will demonstrate a prevention of backsliding.

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in Maintenance Plan Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to Maintenance Plan Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3 and IX.H.4.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other Maintenance Plan conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow – the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – Power Plant Specific Requirements

IX.H.2.h.i.A Boilers #1, #2, and #3 shall not be operated upon commencing operations of Unit #5 (combined-cycle, natural gas-fired combustion turbine).

This condition requires the shutdown of Units 1, 2 and 3 upon commencing operation of the new Unit 5.

IX.H.2.h.i.B Unit #5 shall not exceed the following emission rates to the atmosphere:

POLLUTANT	lb/hr	ppmdv (15% O2 dry)
I. PM_{10} with duct firing: Filterable + condensable	18.8	
II. NOx:		2.0*

* Under steady state operation.

This condition establishes emission requirements for Unit 5.

The ppmvd for the Unit #5 is 2.0 with a calculated mass emission rate of 15.5 lb/hr. The flow rate is determined by 40 CFR Part 60 Appendix A Method 2 and the concentration is determined by 40 CFR Part 60Appendix A Method 7e.

IX.H.2.h.i.C This condition sets the stack testing frequency for Unit #5.

IX.H.2.h.i.D This condition sets the requirements for operation of Units 1, 2, 3 and 4 during the period November 1 to the end of February of the next year.

I. This requires KUC to burn natural gas except during a natural gas curtailment.

II. This condition sets the PM_{10} and NO_x limits for Units 1-4 when natural gas is used as a fuel. PM_{10} limits for Units 1-3 are 0.004 gr/dscf, filterable (2.26 lb/hr) and 0.03 gr/dscf, filterable plus condensable (17.0 lb/hr). PM_{10} limits for Unit 4 is 0.004 gr/dscf, filterable (4.36 lb/hr) and 0.03 gr/dscf, filterable plus condensable (32.7 lb/hr). The NO_x limits for Units 1-3 are 336 ppm (159 lb/hr) and the limit for Unit 4 is 336 ppm (306 lb/hr). In 2018 the limit for Unit 4 will be 60 ppm (31 lb/hr).

III. This condition sets the limits for using coal during a natural gas curtailment. PM_{10} limits for Units 1-3 are 0.029 gr/dscf, filterable (17.3 lb/hr) and 0.29 gr/dscf, filterable plus condensable (382 lb/hr). PM_{10} limits for Unit 4 is 0.029 gr/dscf, filterable (33.5 lb/hr) and 0.29 gr/dscf, filterable plus condensable (382 lb/hr). The NO_x limits for Units 1-3 are 426.5 ppm (216 lb/hr) and the limit Unit 4 is 384 ppm (377 lb/hr).

IV. This condition sets the stack testing frequency for Units 1-4 at once per year if they are operated during the time period November 1 to the end of February the following year.

IX.H.2.h.i.E This condition sets the requirements for operation of Units 1, 2, 3 and 4 during the period March 1 thru October 31.

I. This condition sets the limits for the operation of Units 1, 2, 3 and 4. PM_{10} limits for all units are 0.029 gr/dscf (filterable). The NO_x limits for Units 1-3 are 426.5 ppm (216 lb/hr) and the limit Unit 4 is 384 ppm (377 lb/hr).

II. This condition sets the stack testing frequency for Units 1-4 at once per year if they are operated during the time period March 1 to the end of October. The DAQ does not want KUC to operate the boilers just to test them.

IX.H.2.h.i.F This condition sets sulfur limit and the testing requirements for the sulfur content of coal used as a fuel in the boilers.

A. The sulfur content of any fuel burned shall no exceed 0.66 lb of sulfur per million BTU per test.

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

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

III. KUC shall measure at least 95% of the required increments in any one month that coal is burned in Units 1, 2, 3 or 4.

5.1 Monitoring, Recordkeeping and Reporting

Monitoring for all three emission points is addressed through stack testing. As appropriate, these monitoring requirements are complemented by the general provisions of IX.H.1.e for stack testing, and 1.c for recordkeeping and reporting.

5.2 Discussion of Attainment Demonstration

Generally, the calculation methodology for determination of emissions from the power plant is identical to the method used in during the 1991/1992 timeframe of the original SIP. However, several key differences exist:

1. Units 1-3 will be shut down upon commencement of operation of Unit 5.

2. Condensable emissions, which were excluded from the original SIP, are included in the new maintenance plan

The original SIP was based on filterable PM_{10} emissions only. The new maintenance plan includes both filterable and condensable PM_{10} emissions. The hourly PM_{10} limit listed in IX.H.2.h.i. includes condensable emissions from Units #4 and #5.

6.0 Implementation Schedule

Unit 5 is scheduled to be operational by January 1, 2018

7.0 References

- Kennecott Power Plant, $PM_{2.5}$ SIP Major Point Source RACT Documentation
- UDSHW Contract No. 12601, Work Assignment No. 7, Utah $PM_{2.5}$ SIP RACT Support – TechLaw Inc.
- Power Plant AO DAQE-AN105720025-11
- Power Plant/ Lab/ Tailings Impoundment Title V 3500346002

Evaluation Report – KUC Power Plant

UTAH PM_{10}/ Maintenance Plan

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} Maintenance Plan EVALUATION REPORT
Bonneville Concentrator

1.0 Introduction

The Bonneville (North) Concentrator has been closed down. It ceased operations in 2003 under AO DAQE-AN0572014-03.

2.0 References

- Bonneville Concentrator AO DAQE-AN0572014-03

Evaluation Report – KUC Bonneville Concentrator

UTAH PM_{10} SIP

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP EVALUATION REPORT
Laboratory

1.0 Introduction

The actual emissions from the laboratory are less than one ton per year. This is less than the five tons per year exemption under the rule UAC R307-401-9, Small Source Exemption.

PM_{10} SIP/Maintenance Plan Evaluation Report: Kennecott Utah Copper – Tailings Facility

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
Kennecott – Tailings Facility

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the Utah PM_{10} Maintenance Plan; to address the Salt Lake County PM_{10} Nonattainment Area. This document specifically serves as an evaluation of Kennecott Utah Copper's Tailings Facility.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

These SIP Subsections were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. Thus, this evaluation report also references an earlier SIP version originally dated June 28, 1991. This SIP was adopted by EPA and published in the federal register on July 8, 1994. This earlier SIP version is often referred to as the "original SIP." In order to distinguish between the various documents in this report, a coding scheme will be used:

- Since Section IX.H of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report.
- When referencing the original SIP (the one issued in 1991/1992 and adopted by EPA in 1995), the qualifier $^{\{OS\}}$ will follow any citation from that document.
- When referencing any new SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Kennecott Utah Copper – Tailings Facility
Address: 11984 West Highway 202, Magna, Utah, Salt Lake County
Owner/Operator: Kennecott Utah Copper, LLC
UTM coordinates: 4,515 km Northing, 405 km Easting, Zone 12

1.2 Facility Process Summary

Tailings material, from the concentrating and smelting of concentrate, are transported in slurry form to the tailings storage facility located south of Interstate 80 and west of 8000 West in Salt Lake County, Utah.

1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of installations at the Tailings facility:

- Liquid petroleum-fired emergency generator
- Tailings storage facility

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at the mine, rather it is a listing of all significant emission units.

1.4 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, the Tailings facility baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	23.04
SO_2	0.00
NO_x	0.03

The current PTE values, as established by the most recent AO issued to the source (DAQE-AN10572018-06), are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	36.26
SO_2	0
NO_x	0.26

2.0 Demonstration of Maintaining Attainment

These values have been used in the modeled attainment demonstration. The 2011 actual emissions were used as baseline for model validation. The Tailings facility emissions were projected for future years using growth factors for the mining industry in Salt Lake County. Those emissions projected with growth are intended to represent future actual emissions for the Tailings facility.

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent PM2.5 Section of the SIP. This Section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM10 SIP sources. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11, IX.H.12 and IX.H.13 – which comprise the PM2.5 sections of the SIP, and include this additional RACT application. All requirements from the original PM10 SIP that have not been superseded or replaced, and which are still necessary will also be retained. By necessary, meaning: needed in the demonstration of attainment of the 24-hour standard, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

The Tailings facility is a previously listed SIP source. In the original PM_{10} SIP document for Davis and Salt Lake Counties [IX.H.2 Emission Limitations and Operating Practices (Davis and Salt Lake Counties) – dated 28 June 1991 and Updated 4 November 1992]{OS}, the Tailings facility was listed in Subsection IX.H.2.b.BB.B{OS}. As a listed source there were several requirements and conditions that applied to the facility.

The Tailings facility is not a listed source in the PM2.5 Section of the SIP. As was discussed above in Item 2.0, the limits in this maintenance plan are based on the limits in the PM2.5 SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below:

3.1 Original SIP General Requirements

IX.H.2.a General Requirements{OS}

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a{OS} applied to the listed sources found in Utah County, while those found at IX.H.2.a{OS} applied to the listed sources found in Salt Lake and Davis Counties. The Tailings facility is located in Salt Lake County, only the general requirements of IX.H.2.a{OS} applied. However, except for the additional requirements found under IX.H.2.a.M{OS} for petroleum refineries and the specific fuel requirements of IX.H.2.a.N{OS}, the two subsections are essentially identical.

2.a.A. Stack Testing{OS} – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which incorporates equivalent language.

2.a.B. Visible Emissions{OS} – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.C. Visible Emissions (cont.){OS} – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.D. Annual Emission Limitations{OS} – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists.

2.a.E. Recordkeeping Requirements{OS} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders{OS} – established that this subsection of the SIP superseded any

previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance{OS} – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program.

2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program.

2a.I. Unpaved Operational Areas{OS} – established rules for treating fugitive dust with water sprays or chemical dust suppression.

2.a.J. Actual Emissions{OS} – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsection IX.H of the SIP. This requirement is outdated and obsolete.

2.a.K. Test if Directed{OS} – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions{OS} – established that the definitions contained in R307 apply to Section IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.M. Petroleum Refineries{OS} – This is a fairly lengthy subsection pertaining only to the petroleum refineries. This subsection has its own sub-subsections that are either moved or no longer necessary.

2.a.N. Specific Fuel Requirements for Coal and/or Oil{OS} – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded by the individual source requirements found in IX.H.2 and IX.H.3. This requirement is now, largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources have the ability to burn any other fuel oils.

3.2 Original SIP Source Specific Requirements

Individual source requirements:

In 1995 KUC received approval through AO DAQE-627-95 to construct the North Tailings Impoundment. Since then KUC has revegetated the existing (South) Tailings Impoundment. The discharge system and Arthur pump station on the South Tailings Impoundment were removed when the impoundment area was revegetated.

2.b.BB.B.1.&2.{OS} These subsections describe the previous discharge system at the tailings facility. The infrastructure is in place and is the method used to construct the facility. These

subsections are outdated.

2.b.BB.B.3 and 4.{OS} These subsections describe a dust mitigation measure - redirect deposition to areas susceptible to wind erosion when a wind event is forecasted and also measures for roadways. This mode of operation in inherent to the way the tailings facility is operated with the new discharge system. These subsections are outdated.

2.b.BB.B.5.{OS} This subsection describes a inspection requirements when a wind event is forecast. This subsection is outdated and will be superseded by requirements in new SIP Subsection IX.H.2. Subsection IX.H.2.h.ii.A.II.

2.b.BB.B.6.{OS} This subsection describes the requirements to maximize surface wetness. This requirement has fulfilled and is integral to the operation of the tailings facility. This subsection is outdated and will be superseded by requirements in new SIP Subsection IX.H.2.h.ii.A.

2.b.BB.B.7.{OS} This subsection describes requirements to minimize dust emissions. This requirement has been fulfilled and is an integral to the operation of the tailings facility. This subsection is outdated. See section 5.0 below.

2.b.BB.B.8.{OS} This subsection describes requirements for dike construction and dust mitigation measures. Tailings are placed strategically to ensure that the seismic and geotechnical requirements are met for the impoundment. This subsection is outdated.

2.b.BB.B.9.{OS} This subsection describes requirements for dust mitigation near the Arthur pump station. The Arthur pump station is not in operation since the closure of the South Tailings Impoundment. This subsection is outdated.

2.b.BB.B.10&11.{OS} These subsections describe dust mitigation measures and reporting requirements when a wind event is forecasted. This mode of operation in inherent to the way the tailings facility is operated. These subsection have been replaced by Subsections IX.H.2.h.ii.A.II and III.

2.b.BB.B.12-15.{OS} These subsections require compliance with the state rules and regulations. This subsection will be superseded by the general requirements in IX.H.1. of the maintenance plan.

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions. This recordkeeping requirement includes records of startup/shutdown implementation procedures, as well as CEMS testing data and stack testing data, as applicable.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as

declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – Tailings Facility Specific Requirements

The Tailings facility specific conditions in Section IX.H.2.h.ii address the limitations and requirements that apply only to the Tailings facility. The tailings impoundment is subject to the following requirements in addition to the Fugitive Emissions and Fugitive Dust rule UAC R307-1-4.5

IX.H.2.h.ii.A No more than 50 contiguous acres or more than 5% of the total tailings area shall be permitted to have the potential for wind erosion.

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

II. KUC shall conduct wind erosion potential grid inspections monthly between February 15 and November 15.

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

This subsection requires KUC to prevent fugitive dust by limiting the potential surface area that has the potential for wind erosion. This requirement originated in Condition IX.2.BB.B.6. [OS]

IX.H.2.h.ii.B This condition required KUC to monitor the weather forecast. This requirement monitors for future wind events so that fugitive dust can be minimized during wind events.

A KUC Weather Forecast includes a review of short range and long range weather forecasts. Using the KUC Tailings Impoundment station along with other monitoring data in the area, a specific forecast is issued for the Tailings site. If the analysis forecasts a high wind event (a wind event is defined as wind gusts exceeding 25 mph for more than one hour), the KUC weather forecasts are sent to the Utah Division of Air Quality for necessary surveillance and coordination.

The tailings specific conditions in IX.H.2.h.ii.A &B are comprehensive of tailings operations, are effective in minimizing emission and are applicable at all times. Dust minimization requirements are applicable regardless of wind forecast and are required at all operational areas of the site. The conditions also require additional notification to UDAQ and coordination prior to a wind event. Several of the original SIP requirements are now inherent to the way the facility is operated and the tailings site is constructed. These conditions are no longer necessary and are now captured in the conditions above, applicable to all tailings operations at all times.

IX.H.2.l.i.E KUC is subject to the most recently federally approved fugitive dust rules. The fugitive dust rules that are in R307-1-4.5, Fugitive Emissions and Fugitive Dust. This rule was approved by EPA in 1994 and is applicable to the KUC Tailings facility under the 1994 PM_{10} SIP. This rule sets a minimum for controlling fugitive dust at tailing piles and ponds that are located in the nonattainment area along the Wasatch Front. The subsection R307-1.4.5.5, Tailings Piles and Ponds, outlines the minimum requirements that sources are required to follow in minimizing the fugitive dust from the their operations. Upon EPA approval of a modified fugitive dust rule, KUC will be subject to the modified rule. The EPA will not approve a rule that allows backsliding.

5.1 Monitoring, Recordkeeping and Reporting

Monitoring, recordkeeping and reporting for the conditions above is addressed through a variety of methods, such as visual inspections, field records and reporting.

5.2 Discussion of Attainment Demonstration

Generally, the calculation methodology for determination of emissions for the Tailings facility is similar to the method used in during the 1991/1992 timeframe of the original SIP.

6.0 Implementation Schedule

The requirements imposed on the tailings are effective immediately. While some provision was made for sources generally to implement the RACT requirements of the PM2.5 SIP (and which were included as part of the modeled emission values for each source as discussed in that section above), the tailings did not have any required RACT modifications to undertake. The emission limits listed in IX.H.2.i can be applied immediately. Similarly, the provisions of IX.H.1.a-f (the General Requirements) can also be applied immediately.

8.0 References

- Tailings, $PM_{2.5}$ SIP Major Point Source RACT Documentation
- UDSHW Contract No. 12601, Work Assignment No. 7, Utah $PM_{2.5}$ SIP RACT Support – TechLaw Inc.
- Tailings Approval Order DAQE-AN10572018-06
- Tailings ITA DAQE-IN105720029-14
- Utah Administrative Code R307-1-4.5.

Evaluation Report – Tailings Facility

UTAH PM_{10} SIP/MAINTENANCE PLAN

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report: Kennecott Utah Copper – Molybdenum Autoclave Plant

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
Molybdenum Autoclave Process Plant

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the Utah Maintenance Plan; to address the Salt Lake County PM_{10} Nonattainment Area. This document specifically serves as an evaluation of the Kennecott Utah Copper's Molybdenum Autoclave Process (MAP) Plant.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, Maintenance Plan Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

These SIP Subsections were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. Thus, this evaluation report also references an earlier SIP version originally dated June 28, 1991. This SIP was adopted by EPA and published in the federal register on July 8, 1994. This earlier SIP version is often referred to as the "original SIP." In order to distinguish between the various documents in this report, a coding scheme will be used:

- Since Section IX.H of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report.
- When referencing the original SIP (the one issued in 1991/1992 and adopted by EPA in 1995), the qualifier $^{\{OS\}}$ will follow any citation from that document.
- When referencing any new SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Kennecott Utah Copper Molybdenum Autoclave Process Plant
Address: 12000 West 2100 South, Magna, Utah, Salt Lake County
Owner/Operator: Kennecott Utah Copper, LLC
UTM coordinates: 4,508,950 m Northing, 401,300 m Easting, Zone 12

1.2 Facility Process Summary

Kennecott Utah Copper is constructing the Molybdenum Autoclave Process plant in Magna, located in Salt Lake County, Utah. In the copper ore, molybdenum exists as molybdenum

disulfide (MoS2). The Copperton Concentrator produces bulk concentrate which consists of copper, molybdenum, gold, and silver among other metals. The molybdenum concentrate is separated from the bulk concentrate using differential flotation. KUC is adding a Molybdenum Autoclave Process (MAP) plant, which will process MoS_2 into MoO_3.

1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of the main emitting units from the KUC MAP plant:

- Combined Heat and Power (CHP) Unit
- Packaging Area Dust Collector
- Calciner
- Dryers
- Reoxidizer

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at the MAP plant, rather it is a listing of all significant emission units or emission unit groups.

1.4 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, the MAP plant did not exist and therefore does not have actual emissions.

The current PTE values for the Kennecott Utah Copper MAP plant, as established by the most recent AO issued to the source (DAQE-AN103460052-13), are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10} (filterable)	13.11
SO_2	2.43
NO_x	35.57

2.0 Demonstration of Maintaining Attainment

Unlike the base year inventory, which used only the 2011 actual emissions for each source to set the baseline for modeling, a modified version of the PTE values was used for the modeled attainment demonstration. Generally speaking, beginning with the PTE values listed in Table 2 (from the most recent approval order issued to each source), these values were "trued-up" by including the expected effects from implementation of RACT from the PM2.5 SIP. This yields a 2019 Projected Emission Value for each of the pollutants of concern. Where necessary, these values were corrected for condensable particulates using simple correction factors based on fuel consumed or process type.

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent $PM_{2.5}$ Section of the SIP. This Section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM_{10} SIP sources – including the KUC MAP plant in

specific. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11, IX.H.12 and IX.H.13 – which comprise the $PM_{2.5}$ sections of the SIP, and include this additional RACT application. All requirements from the original PM_{10} SIP that have not been superseded or replaced, and which are still necessary will also be retained. By necessary, meaning: needed in the demonstration of attainment of the 24-hour standard, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

The KUC MAP plant is a not a previously listed SIP source. It was permitted after original PM_{10} SIP document for Davis and Salt Lake Counties [dated 28 June 1991 and Updated 4 November 1992]{OS}, was written.

However, it is a listed source in the PM2.5 Section of the SIP (see SIP Section IX.H.12.n.iii). As was discussed above in Item 2.0, all limits in this maintenance plan are based on the limits in the PM2.5 SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.n.iii.

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in Maintenance Plan Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to Maintenance Plan Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions. This recordkeeping requirement includes records of startup/shutdown implementation procedures, as well as CEMS testing data and stack testing data, as applicable.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate

defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other Maintenance Plan conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow – the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as

a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – MAP Plant Specific Requirements

IX.H.2.n.iii.A This condition establishes limits for the natural gas turbine with duct burner and TEG firing.

The CHP has a limit for NO_x.

Combined Heat Plant	NO_x 5.01 lbs/hr

IX.H.2.n.iii.B This condition establishes a stack test frequency for the CHP.

The CHP is still under construction and is not in operation. When the CHP begins operation, KUC will be required to test the NO_x emission limits annually.

IX.H.2.n.iii.D This subsection requires KUC to use standard operating procedures during start-up and shut-down to minimize emissions.

The MAP, refinery and smelter are permitted together in the same Title V permit because of their location. The processes at the smelter and refinery are dependent on each other but the process at the MAP is independent of them. The refinery processes copper plates from the smelter and then sends the plates back to the smelter. The smelter then processes the plates again before finished copper is shipped off site. The MAP will receive ore from the Bingham Canyon Mine that has a higher concentration of molybdenum than the ore concentrate that is sent to the smelter.

The majority of the Molybdenum ore body is the located in the bottom of the Bingham Canyon Mine and it is covered with waste material. When the mine had a slide in 2013, it covered the bottom of the open pit mine and the equipment that was located at the bottom of the mine. Since the slide at the mine on April 2013, KUC has been moving the waste material from the slide. They have to haul to material from the bottom of the pit to the ore dumping sites that are located at the top of the pit. The 30,000 mileage limit prevents them from moving it out quickly. KUC will probably not be operating the MAP unit until after the cleanup has been finished.

5.1 Monitoring, Recordkeeping and Reporting

Monitoring for all the CHP emission point is addressed through a stack testing. As appropriate, this monitoring requirement is complemented by the general provisions of IX.H: 1.a for stack testing, and 1.c for recordkeeping and reporting.

5.2 Discussion of Attainment Demonstration

Generally, the calculation methodology for determination of emissions from the PM_{10} SIP sources is identical to the method used in during the 1991/1992 timeframe of the original SIP. However, condensable emissions, which were excluded from the original SIP, are included in the

new maintenance plan. The original SIP was based on filterable PM_{10} emissions only. The new maintenance plan includes both filterable and condensable PM_{10} emissions. The MAP facility is not a listed source in the original PM_{10} SIP.

6.0 Implementation Schedule

The requirements imposed on the MAP will be effective upon commencement of operations. While some provision was made for sources generally to implement the RACT requirements of the PM2.5 SIP (and which were included as part of the modeled emission values for each source as discussed in that section above), the MAP did not have any required RACT modifications to undertake. The emission limits listed in IX.H.2.j can be applied immediately. Similarly, the provisions of IX.H.1.a-f (the General Requirements) can also be applied immediately.

7.0 References

- Kennecott MAP, $PM_{2.5}$ SIP Major Point Source RACT Documentation
- UDSHW Contract No. 12601, Work Assignment No. 7, Utah $PM_{2.5}$ SIP RACT Support – TechLaw Inc.
- MAP AO DAQE-AN103460052-13

Evaluation Report – KUC MAP

UTAH PM_{10} SIP/MAINTENANCE PLAN

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report: Kennecott Utah Copper - Refinery

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
KUC Refinery

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.3 of the Utah Maintenance Plan; to address the Salt Lake County PM_{10} Nonattainment Area. This document specifically serves as an evaluation of the Kennecott Utah Copper Refinery facility.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

These SIP Subsections were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. Thus, this evaluation report also references an earlier SIP version originally dated June 28, 1991. This SIP was adopted by EPA and published in the federal register on July 8, 1994. This earlier SIP version is often referred to as the "original SIP." In order to distinguish between the various documents in this report, a coding scheme will be used:

- Since Section IX.H of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report.
- When referencing the original SIP (the one issued in 1991/1992 and adopted by EPA in 1995), the qualifier $^{\{OS\}}$ will follow any citation from that document.
- When referencing any new SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Kennecott Utah Copper Refinery
Address: 12000 West 2100 South, Magna, Utah, Salt Lake County
Owner/Operator: Kennecott Utah Copper, LLC
UTM coordinates: 4,508,450 m Northing, 401,550 m Easting, Zone 12

1.2 Facility Process Summary

Kennecott Utah Copper LLC operates a copper Refinery in Salt Lake County, Utah. Molten copper at approximately 99.5 percent purity is cast into plate anodes at the Smelter and sent to the

Refinery for further purification. At the Refinery, anodes are lowered into an electrolyte solution where for 10 days, an electric current is sent between the anode and the cathode, causing the copper ions to migrate to a steel sheet forming a plate cathode of 99.99 percent pure copper.

1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of the main emitting units from the Kennecott Utah Copper Refinery:

- Electrolytic Refining Tanks and associated control devices
- Cathode and Anode Scrap Washing
- Precious Metals operations and associated control devices
- Tankhouse Boilers
- Storage Tanks
- Emergency Generators (diesel and LPG)
- Combined Heat and Power Unit

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at the Refinery, rather it is a listing of all significant emission units or emission unit groups.

1.4 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, the Refinery baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	10.02
SO_2	0.85
NO_x	20.63

The current PTE values for the Kennecott Utah Copper Refinery, as established by the most recent AO issued to the source (DAQE-AN103460045-10) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	25.64
SO_2	4.44
NO_x	38.57

2.0 Demonstration of Maintaining Attainment

Unlike the base year inventory, which used only the 2011 actual emissions for each source to set the baseline for modeling, a modified version of the PTE values was used for the modeled attainment demonstration. Generally speaking, beginning with the PTE values listed in Table 2 (from the most recent approval order issued to each source), these values were “trued-up” by including the expected effects from implementation of RACT from the PM2.5 SIP. This yields a 2019 Projected Emission Value for each of the pollutants of concern. Where necessary, these

values were corrected for condensable particulates using simple correction factors based on fuel consumed or process type.

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent PM2.5 Section of the SIP. This Section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM10 SIP sources – including the Kennecott Utah Copper Refinery in specific. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11, IX.H.12 and IX.H.13 – which comprise the PM2.5 sections of the SIP, and include this additional RACT application. All requirements from the original PM10 SIP that have not been superseded or replaced, and which are still necessary will also be retained. By necessary, meaning: needed in the demonstration of attainment of the 24-hour standard, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

The Kennecott Refinery is a previously listed SIP source. In the original PM_{10} SIP document for Davis and Salt Lake Counties [IX.H.2 Emission Limitations and Operating Practices (Davis and Salt Lake Counties) – dated 28 June 1991 and Updated 4 November 1992]$^{\{OS\}}$, the Refinery was listed in Subsection IX.H.2.b.Y$^{\{OS\}}$ as Kennecott Utah Copper Refinery, Garfield, Utah. As a listed source there were several requirements and conditions that applied to the facility.

In addition, the Refinery is also a listed source in the PM2.5 Section of the SIP (see SIP Section IX.H.12.n.i). As was discussed above in Item 2.0, all limits in this maintenance plan are based on the limits in the PM2.5 SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.n.ii. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below:

3.1 Original SIP General Requirements

IX.H.2.a General Requirements$^{\{OS\}}$

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a$^{\{OS\}}$ applied to the listed sources found in Utah County, while those found at IX.H.2.a$^{\{OS\}}$ applied to the listed sources found in Salt Lake and Davis Counties. As the then the Refinery was located in Salt Lake County, only the general requirements of IX.H.2.a$^{\{OS\}}$ applied. However, except for the additional requirements found under IX.H.2.a.M$^{\{OS\}}$ for petroleum refineries and the specific fuel requirements of IX.H.2.a.N$^{\{OS\}}$, the two subsections are essentially identical.

2.a.A. Stack Testing$^{\{OS\}}$ – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which incorporates equivalent language.

2.a.B. Visible Emissions$^{\{OS\}}$ – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.C. Visible Emissions (cont.)$^{\{OS\}}$ – covered the procedure by which visible emission

observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.D. Annual Emission Limitations{OS} – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists.

2.a.E. Recordkeeping Requirements{OS} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders{OS} – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance{OS} – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program.

2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program.

2a.I. Unpaved Operational Areas{OS} – established rules for treating fugitive dust with water sprays or chemical dust suppression.

2.a.J. Actual Emissions{OS} – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsection IX.H of the SIP. This requirement is outdated and obsolete.

2.a.K. Test if Directed{OS} – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions{OS} – established that the definitions contained in R307 apply to Section IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.M. Petroleum Refineries{OS} – This is a fairly lengthy subsection pertaining only to the petroleum refineries. This subsection has its own sub-subsections that are either moved or no longer necessary.

2.a.N. Specific Fuel Requirements for Coal and/or Oil{OS} – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded by the individual source requirements found in IX.H.2 and IX.H.3 (see specifically the sources Kennecott and BYU). This requirement is now, largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel

fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources have the ability to burn any other fuel oils.

3.3 Original SIP Source Specific Requirements

Kennecott Utah Copper initiated a modernization project in the mid-1990s, which included the Refinery along with the Smelter.

Individual source requirements:

2.b.Y.1.{OS} This subsection was a listing of the equipment at the Refinery – this subsection has been superseded and is irrelevant. A simple listing of equipment does not constitute an emission limitation, does not impose any restriction on daily emissions, and rapidly becomes out of date as well as impossible to enforce. The original listing found in this subsection does not match the current equipment installed and operating at the Refinery and would represent a significant step backwards in emission control and refining technology.

2.b.Y.2.{OS} Stack emission limits. This subsection is irrelevant. The pieces of equipment with stack testing limits have been removed/replaced when the Refinery was modernized and reconstructed in the mid-1990s.

2.b.Y.3.{OS} Testing frequencies for equipment limits listed in subsection 2.b.Y.2.{OS}. This subsection is irrelevant. These pieces of equipment have been removed/replaced when the Refinery was modernized and reconstructed in the mid-1990s.

2.b.Y.4.{OS} Opacity limits. This subsection is irrelevant. These pieces of equipment have been removed when the Refinery was modernized and reconstructed in the mid-1990s. This subsection is irrelevant. These pieces of equipment have been removed/replaced when the Refinery was modernized and reconstructed in the mid-1990s.

2.b.Y.5.{OS} Basis for minimizing SO_2 emissions from the Selenium Extraction Process. This subsection required Kennecott Utah Copper to monitor parameters in order to minimize SO_2 on a daily basis. This subsection is irrelevant. These pieces of equipment have been removed when the Refinery was modernized and reconstructed in the mid-1990s.

2.b.Y.6.{OS} This subsection established requirements for the Dore' furnace secondary hood baghouse. This subsection is irrelevant. These pieces of equipment have been removed when the Refinery was modernized and reconstructed in the mid-1990s.

2.b.Y.7.{OS} This subsection sets limits for the total fuel consumption including coal and #2 fuel oil. Kennecott Utah Copper has modified its combustion operations at the Refinery. Therefore, this subsection is irrelevant.

2.b.Y.8.{OS} This subsection established when Kennecott Utah Copper could use natural gas, fuel oil or coal. Kennecott Utah Copper has modified its combustion operations at the Refinery. Therefore, this subsection is irrelevant.

2.b.Y.9.{OS} This required the fugitive emissions from coal piles and associated roads to be minimized by water spraying. This subsection is irrelevant. Kennecott Utah Copper is not allowed to burn coal at the Refinery.

2.b.Y.10.{OS} This subsection set conditions for the burning of coal at the Refinery boilers. This subsection is irrelevant. Kennecott Utah Copper is not allowed to burn coal at the Refinery.

2.b.Y.11.{OS} This subsection set conditions for the burning of coal at the Refinery steam plant. This subsection is irrelevant. Kennecott Utah Copper is not allowed to burn coal at the Refinery.

2.b.Y.12.{OS} This subsection required Kennecott Utah Copper to notify the Executive Secretary when coal was burned in order for DAQ to conduct an inspection. This subsection is irrelevant. Kennecott Utah Copper is not allowed to burn coal at the Refinery.

2.b.Y.13.{OS} Annual Emissions – established total annual emissions for the entire Refinery. The emissions from the Refinery have significantly reduced since the original PM_{10} SIP was approved. The PM_{10} standard is a 24-hour standard. Therefore, the annual limits have been eliminated. Salt Lake County has not shown an exceedance in over ten years and the reduction in allowable emissions, see table 3, will demonstrate a prevention of backsliding.

Table 3: Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
Current PM_{10}	25.64
Current SO_2	4.44
Current NO_x	38.57
Original SIP PM_{10}	51.9
Original SIP SO_2	162.6
Original SIP NO_x	121.0

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions. This recordkeeping requirement includes

records of startup/shutdown implementation procedures, as well as CEMS testing data and stack testing data, as applicable.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow – the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance

demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – Refinery Specific Requirements

There are nine pieces of equipment with limits listed in the AO (DAQE-AN0103460045-10) and the Title V. These nine pieces of equipment were not listed in the 1994 PM_{10} SIP. The two boilers and the turbine are included in the proposed PM_{10} SIP limits. The boilers, in 1994, were rated at 67 MMBTU/hr and have been replaced with boilers that are now rated at 82 MMBTU/hr. The new boilers have low NO_x burners and flue gas recirculation. The remaining pieces of equipment were not included because of the type or the size of the emission rate (less than 1.0 lb/hr). The Demister Pads have an acid mist limit with the Liberator having the highest limit set at 0.46 lb/hr (0.004 gr/dscf). When it was tested in March 2012, the results were less than 0.0001 gr/dscf. Based on this fact and that acid is not a PM_{10} precursor, the demister pads were not included in the proposed PM_{10} Maintenance Plan.

The Precious Metals Recovery scrubber has an SO_2 emission rate of 1.77 lb/hr (42 lbs/hr). It was tested in May 2012 and it had an emission rate of 0.1 lb/hr (2.4 lbs/day). The Silver Production scrubber has an H_2SO_4 emission rate of 0.22 lb/hr (5.2 lbs/hr). It was tested in May 2012 and it had an emission rate of 0.004 lb/hr (0.096 lb/day). The Gold/Silver Recovery Baghouse has a PM_{10} stack test limit of 0.43 lb/hr (10.3 lbs/day). It was tested in March 2012 and it has an emission rate of 0.005 lb/hr (0.12 lbs/day). Based on the emission limits and the tested emission rates, these sources were not included in the proposed PM_{10} Maintenance Plan.

The opacity limits for source specific emission units have not been included in the PM_{10} Maintenance Plan for KUC. Opacity readings do not usually have a direct correlation with the emission rates. An opacity reading has to be taken at the time of the stack test in order to set a correlation with the emission rates. Most of the emission points at the refinery have an opacity limit of 15% or less. All of these emission points listed above have no visible emissions unless there is an upset of the control unit. An opacity limit will not limit the emission rates or allow a visual check on the emission rates from these sources. Therefore, an opacity limit has not been set for these emission points.

IX.H.2.n.ii.A This condition establishes limits for the two Tankhouse boilers and the Combined Heat Plant.

The new boiler NO_x limits are lower than the original SIP boiler limits.

Tankhouse Boilers	1994(67.4 MMBTU/hr)	New (82 MMBTU/hr)
NO_X	0.6 lb/MMBTU	
	40.4 lbs/hr	9.5 lbs/hr

The Combined Heat Plant has a NO_X emission rate of 5.96 lbs/hr (0.07 tons/day)

IX.H.2.n.ii.B This condition establishes stack test frequencies for the boilers. The boiler NO_x emission limits are tested every three years and the combined Heat Plant is tested annually. The boilers uses are subject to the NSPS standards in Subpart Db-Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

IX.H.2.n.ii.C This subsection requires Kennecott Utah Copper to use standard operating procedures during start-up and shut-down to minimize emissions.

5.1 Monitoring, Recordkeeping and Reporting

Monitoring for all three emission points is addressed through stack testing. As appropriate, these monitoring requirements are complemented by the general provisions of IX.H: 1.e for stack testing, and 1.c for recordkeeping and reporting.

5.2 Discussion of Attainment Demonstration

Generally, the calculation methodology for determination of emissions from the refinery is identical to the method used in during the 1991/1992 timeframe of the original SIP. However, one key difference exists:

1. Emissions in the new maintenance plan are lower or equal to the original SIP

As is shown above in Table 4, the emissions of PM_{10}, NO_X and SO_2 for the Refinery have decreased from those listed in the original SIP.

2. Condensable emissions, which were excluded from the original SIP, are included in the new maintenance plan

The original SIP was based on filterable PM_{10} emissions only. The new maintenance plan modeled both filterable and condensable PM_{10} emissions.

6.0 Implementation Schedule

The requirements imposed on the Refinery are currently and will remain in effect. While some provision was made for sources generally to implement the RACT requirements of the PM2.5 SIP (and which were included as part of the modeled emission values for each source as discussed in that section above), the refinery did not have any required RACT modifications to undertake. The emission limits listed in IX.H.2.i can be applied immediately. Similarly, the provisions of IX.H.1.a-f (the General Requirements) can also be applied immediately.

7.0 References

- KENNECOTT UTAH COPPER Refinery, $PM_{2.5}$ SIP Major Point Source RACT Documentation
- UDSHW Contract No. 12601, Work Assignment No. 7, Utah $PM_{2.5}$ SIP RACT Support – TechLaw Inc.
- Refinery AO DAQE-AN103460045-10
- Refinery stack test reports for 2012 stack tests
- Smelter/Refinery Title V 3500030003

Evaluation Report – Kennecott Utah Copper Refinery

UTAH PM_{10} SIP/MAINTENANCE PLAN

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report: Kennecott Utah Copper- Smelter

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
KUC Smelter

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.3 of the Utah Maintenance Plan; to address the Salt Lake County PM_{10} Nonattainment Area. This document specifically serves as an evaluation of the Kennecott Utah Copper Smelter located in Salt Lake County.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

These SIP Subsections were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. Thus, this evaluation report also references an earlier SIP version originally dated June 28, 1991. This SIP was adopted by EPA and published in the federal register on July 8, 1994. This earlier SIP version is often referred to as the "original SIP." In order to distinguish between the various documents in this report, a coding scheme will be used:

- Since Section IX.H of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report.
- When referencing the original SIP (the one issued in 1991/1992 and adopted by EPA in 1995), the qualifier $^{\{OS\}}$ will follow any citation from that document.
- When referencing any new SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Kennecott Utah Copper Smelter
Address: 12000 West 2100 South, Magna, Utah, Salt Lake County
Owner/Operator: Kennecott Utah Copper, LLC
UTM coordinates: 4,508,000 m Northing, 399,000 m Easting, Zone 12

1.2 Facility Process Summary

Kennecott Utah Copper operates a copper smelter in Salt Lake County, Utah. The Smelter processes copper concentrate by means of flash smelting and flash converting furnaces.

Molten copper at approximately 99.5 percent purity is cast into plate anodes to be sent to the Kennecott Refinery for further purification.

1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of the main emitting units from the KUC Smelter:

- Main Stack Operations
  - Rotary Dryer
  - Furnace operations
  - Matte Drying and Grinding Plant
  - Anode Area operations
  - Acid Plant
  - Powerhouse boiler and superheater
- Powerhouse Holman Boiler
- Material handling and associated control equipment
- Small nature gas combusting equipment
- Emergency Equipment (Diesel)
- Emergency Equipment (Natural Gas)

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at the smelter, rather it is a listing of all significant emission units or emission unit groups.

The Main Stack table below outlines the emission sources that vent to the Main Stack. It is divided by emission type (PM_{10} SO_2 and NO_x) and emission source. Each source may appear more than once because the table is divided by emission type.

Main Stack Source Table

Source Name	Source Description
PM_{10} Emissions – 89.5 lb/hr (filterable, daily average)	**The following sources contribute to the PM_{10} emissions measured at the main stack.**
Hot Metals Building	The secondary gas system collects fugitive emissions in the Hot Metals Building (typically associated with the furnaces) and vents them through a baghouse and a sodium based scrubber before they are vented to the Main Stack.
Concentrate Dryer	The concentrate dryer burns natural gas to heat/dry concentrate for use in the FS furnace. It is operated with low-NOx burners along with lower dryer temperatures minimizes the formation of NOx while also preventing the formation of SO_2. Kennecott operates both a baghouse and a scrubber as controls for the concentrate dryer.
Matte Grinding Circuit	The Matte Grinding circuit crushes and dries granulated matte for use in the Flash Converting furnace. The ground matte is collected in a baghouse and pneumatically conveyed to the Flash Converting furnace feed bin. NOx emissions from natural gas combustion are controlled with Low NOx burners and low

	temperature firing and PM10 emissions are controlled with the production baghouse.
Anode Area	In the anodes area, blister copper from the Flash Converting furnace is refined in two available refining furnaces to remove the final traces of sulfur. Copper production can be supplemented with copper scrap which can be added to the refining furnaces for re-melt. The anodes refining furnaces are natural gas fired with oxy-fuel burners. Off-gas is vented (in series) to a quench tower, lime injection, baghouse, and scrubber and vented to the Main Stack. NOx reduction activities also include maintaining furnaces to prevent ingress of air.
Anode Area Shaft and Holding Furnaces	The Shaft furnace and holding furnace are used to re-melt anode scrap and other copper scrap to incorporate into copper production. Low NOx burners are used to reduce NOx from the natural gas combustion and a baghouse is operated to control PM10 emissions. The Shaft furnace is located in the anodes area, but vents separately to the Main Stack.
NO_X Emissions – 35 lb/hr, annual average	**The following sources contribute to the NO_X emissions measured at the main stack.**
Concentrate Dryer	The concentrate dryer burns natural gas to heat/dry concentrate for use in the FS furnace. It is operated with low-NOx burners along with lower dryer temperatures minimizes the formation of NOx while also preventing the formation of SO_2. Kennecott operates both a baghouse and a scrubber as controls for the concentrate dryer.
Matte Grinding Circuit	The Matte Grinding circuit crushes and dries granulated matte for use in the Flash Converting furnace. The ground matte is collected in a baghouse and pneumatically conveyed to the Flash Converting furnace feed bin. NOx emissions from natural gas combustion are controlled with Low NOx burners and low temperature firing and PM10 emissions are controlled with the production baghouse.
Anode Area	In the anodes area, blister copper from the Flash Converting furnace is refined in two available refining furnaces to remove the final traces of sulfur. Copper production can be supplemented with copper scrap which can be added to the refining furnaces for re-melt. The anodes refining furnaces are natural gas fired with oxy-fuel burners. Off-gas is vented (in series) to a quench tower, lime injection, baghouse, and scrubber and vented to the Main Stack. NOx reduction activities also include maintaining furnaces to prevent ingress of air.
Anode Area Shaft and Holding Furnaces	The Shaft furnace and holding furnace are used to re-melt anode scrap and other copper scrap to incorporate into copper production. Low NOx burners are used to reduce NOx from the natural gas combustion and a baghouse is operated to control PM10 emissions. The Shaft furnace is located in the anodes area, but vents separately to the Main Stack.

Foster Wheeler Boiler	The boiler is used to provide process steam at the Smelter. The boiler is ducted to the main stack and is equipped with Low NO_X Burners and Flue Gas Recirculation.
Powerhouse Superheater	The Powerhouse superheater provides a supplemental source of heat for the steam produced by the smelter waste heat boilers, which is used to drive the acid plant compressors and the smelter turbine generator. The superheater off gasses are ducted to the main stack. NOx emissions are controlled by ultra-low NOx burners and flue gas recirculation.
SO_2 Emissions – 552 lb/hr, 3-hour rolling average	**The following sources contribute to the SO_2 emissions measured at the main stack.**
Concentrate Dryer	The concentrate dryer burns natural gas to heat/dry concentrate for use in the FS furnace. It is operated with low-NOx burners along with lower dryer temperatures minimizes the formation of NOx while also preventing the formation of SO_2. Kennecott operates both a baghouse and a scrubber as controls for the concentrate dryer.
Anode Area	In the anodes area, blister copper from the Flash Converting furnace is refined in two available refining furnaces to remove the final traces of sulfur. Copper production can be supplemented with copper scrap which can be added to the refining furnaces for re-melt. The anodes refining furnaces are natural gas fired with oxy-fuel burners. Off-gas is vented (in series) to a quench tower, lime injection, baghouse, and scrubber and vented to the Main Stack. NOx reduction activities also include maintaining furnaces to prevent ingress of air.
Hot Metals Building	The secondary gas system collects fugitive emissions in the Hot Metals Building (typically associated with the furnaces) and vents them through a baghouse and a sodium based scrubber before they are vented to the Main Stack.
Acid Plant	The double contact acid plant removes SO_2 from the off gases of the furnaces. The sulfuric acid produced by the plant is sold. Among other technologies, the system is equipped with tubular candle fiber mist eliminators and the tail gas is discharged to the main stack.

1.4 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, the smelter baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	247.68

SO_2	695.89
NO_x	157.44

The current PTE values for the KUC Smelter, as established by the most recent AO issued to the source (DAQE-AN103460054-14) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	510.82
SO_2	1,085.72
NO_x	185.29

2.0 Demonstration of Maintaining Attainment

These values have been used in the modeled attainment demonstration. The 2011 actual emissions were used as baseline for model validation. The Smelter emissions were projected for future years using growth factors for the manufacturing industry in Salt Lake County. Those emissions projected with growth are intended to represent future actual emissions for the Smelter.

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent PM2.5 Section of the SIP. This Section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM10 SIP sources – including the KUC Smelter in specific. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11, IX.H.12 and IX.H.13 – which comprise the PM2.5 sections of the SIP, and include this additional RACT application. All requirements from the original PM10 SIP that have not been superseded or replaced, and which are still necessary will also be retained. By necessary, meaning: needed in the demonstration of attainment of the 24-hour standard, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

The KUC Smelter is a previously listed SIP source. In the original PM_{10} SIP document for Davis and Salt Lake Counties [IX.H.2 Emission Limitations and Operating Practices (Davis and Salt Lake Counties) – dated 28 June 1991 and Updated 4 November 1992]$^{\{OS\}}$, the smelter was listed in Subsection IX.H.2.b.V$^{\{OS\}}$ as Kennecott Utah Copper Smelter. As a listed source there were several requirements and conditions that applied to the facility.

In addition, the smelter is also a listed source in the PM2.5 Section of the SIP (see SIP Section IX.H.12.n.i). As was discussed above in Item 2.0, all limits in this maintenance plan are based on the limits in the PM2.5 SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.n.i. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below:

3.1 Original SIP General Requirements

IX.H.2.a General Requirements$^{\{OS\}}$

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a{OS} applied to the listed sources found in Utah County, while those found at IX.H.2.a{OS} applied to the listed sources found in Salt Lake and Davis Counties. As the then Smelter was located in Salt Lake County, only the general requirements of IX.H.2.a{OS} applied. However, except for the additional requirements found under IX.H.2.a.M{OS} for petroleum refineries and the specific fuel requirements of IX.H.2.a.N{OS}, the two subsections are essentially identical.

2.a.A. Stack Testing{OS} – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which incorporates equivalent language.

2.a.B. Visible Emissions{OS} – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.C. Visible Emissions (cont.){OS} – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.D. Annual Emission Limitations{OS} – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists.

2.a.E. Recordkeeping Requirements{OS} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders{OS} – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance{OS} – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program.

2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program.

2a.I. Unpaved Operational Areas{OS} – established rules for treating fugitive dust with water sprays or chemical dust suppression.

2.a.J. Actual Emissions{OS} – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsection IX.H of the SIP. This requirement is outdated and obsolete.

2.a.K. Test if Directed{OS} – established a definition of this term. No longer needed as this term

is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions{OS} – established that the definitions contained in R307 apply to Section IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.M. Petroleum Refineries{OS} – This is a fairly lengthy subsection pertaining only to the petroleum refineries. This subsection has its own sub-subsections that are either moved or no longer necessary. This section is not applicable to the KUC Smelter.

2.a.N. Specific Fuel Requirements for Coal and/or Oil{OS} – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded by the individual source requirements found in IX.H.2 and IX.H.3 (see specifically the sources Kennecott and BYU). This requirement is now, largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources have the ability to burn any other fuel oils.

3.3 Original SIP Source Specific Requirements

KUC initiated a Smelter modernization project in the mid-1990s, thus constructing and now operating one of the cleanest copper smelters in the world. The modernization lead to major reductions in emissions from its smelting operations. These SIP conditions are therefore no longer current.

The U.S. E.P.A. performed extensive technology reviews of smelter emissions in support of the 2002 primary copper smelting major source MACT standard (40 CFR 63 Subpart QQQ) and the 2007 primary copper smelting area source MACT standard (40 CFR 63 Subpart EEEEEE). Specific discussion of the unique aspects of pollution controls at the KUC Smelter are included in the Federal Register notices associated with the draft and final promulgation of both of these rules. Both of these standards go so far as to establish a separate category for only the KUC Smelter due to its unique design and emission performance not achievable by conventional technology. The primary copper smelting area source MACT standard specifically identifies KUC Smelter main stack emission performance as MACT for copper smelters (existing sources not using batch copper converters). Smelter process and emission controlling technologies that contributed to EPA's designation of the modernized smelter as a separate MACT category for HAP emissions, including off gases from furnaces, also contribute to the control of fine particulate and precursor emissions.

The Federal Register 72FR2930, January 23, 2007 has additional information on the MACT standard. No new major developments in technologies or costs have occurred subsequent to promulgation of the MACT standards.

Table 3 shows the reduction from the smelter upgrade.

Table 3: Potential to Emit

Pollutant	Potential to Emit (Tons/Year)

Current PM_{10}	510.82
Current SO_2	1,085.72
Current NO_x	185.29
Original SIP PM_{10}	1,340
Original SIP SO_2	18,575
Original SIP NO_x	145

Individual source requirements:

2.b.V.A.1.{OS} This subsection was a listing of the equipment at the smelter – this subsection has been superseded and is irrelevant. A simple listing of equipment does not constitute an emission limitation, does not impose any restriction on daily emissions, and rapidly becomes out of date as well as impossible to enforce. The original listing found in this subsection does not match the current equipment installed and operating at the smelter and would represent a significant step backwards in emission control and smelting technology.

2.b.V.A.2.{OS} Emission limits for the Powerhouse and Rotary Concentrate Dryer Stack. This subsection is irrelevant because it is for equipment that has been removed or replaced when the "new-upgraded" smelter was constructed in 1994.

2.b.V.A.3.{OS} Testing frequencies for Rotary Concentrate Dryer Stack. This subsection is irrelevant because it is for equipment that has been removed or replaced when the "new-upgraded" smelter was constructed in 1994.

2.b.V.A.4.{OS} Opacity limits. This subsection is irrelevant because it is for equipment that has been removed or replaced when the "new-upgraded" smelter was constructed in 1994.

2.b.V.A.5.{OS} Opacity observations. This subsection is irrelevant. These pieces of equipment have been removed when the "new-upgraded" smelter was constructed in 1994.

2.b.V.A.6.{OS} Water sprays for equipment. This subsection is irrelevant. These pieces of equipment have been removed when the "new-upgraded" smelter was constructed in 1994.

2.b.V.A.7.{OS} Natural gas requirement for the Powerhouse and Rotary Dryer. This subsection is irrelevant because it is for equipment that has been removed or replaced when the "new-upgraded" smelter was constructed in 1994.

2.b.V.A.8.{OS} This subsection is for the operation and maintenance of the primary and secondary hooding systems; dust collection mechanism of waste heat boilers, dropout chambers and shot coolers; hot cyclones; and dry electrostatic precipitators. This subsection is irrelevant because it is for equipment that has been removed or replaced when the "new-upgraded" smelter was constructed in 1994.

2.b.V.A.9.{OS} This was a requirement for meeting the main stack emission limit for PM. This subsection has been replaced with limits for PM10 and PM2.5.

2.b.V.A.10.{OS} This subsection outlines SO2 emission limit compliance. This subsection is irrelevant. New main stack emission limits have been established with the appropriate stack testing requirements.

2.b.V.A.11.{OS} This subsection outlines compliance demonstration for the main stack opacity limits. Subsection IX.H.1.f of the new maintenance plan covers the use of CEMs and opacity monitoring. Therefore, this subsection is irrelevant.

2.b.V.A.12.{OS} This subsection outlines the requirements for startup/shutdown. This section is irrelevant because it is for equipment that has been removed or replaced when the "new – upgraded" smelter was constructed in 1994.

2.b.V.A.13.{OS} This a statement that the section outlined above is effective upon adoption by the Committee. This subsection is irrelevant.

2.b.V.B.1.{OS} This subsection sets main stack and acid plant emission limits. The emission limits have been revised with the "new-upgraded" Smelter so these are superseded by the updated limits in subsection IX.H.2. The emission for the main stack in the condition set the PM_{10} at 400 lbs/hr (24 hour average) and the new limit is 89.5 lbs/hr (daily average). In the 1994 SIP, the SO_2 main stack limit was 6,450 lb/hr (3 hour average) and the new limit is 552 lbs/hr (3 hour average).

Table 4: Main Stack Comparison

Pollutant	1994 SIP	Maintenance Plant
PM_{10} daily average		
Filterable	400 lb/hr	89.5 lb/hr
Filterable + condensable		439 lb/hr
SO_2		
3-hr average	6,450 lb/hr	552 lb/hr
Daily average	5,700 lb/hr	422 lb/hr

The acid plant SO_2 emissions are vented to the main stack. The SO_2 emissions (1,050 ppmdv 3-hr ave and 650 ppmdv 6-hr ave) are included in the main stack limits (522 lb/hr 3-hr ave and 422 lb/hr 6-hr ave. Based on the fact that these emissions are not emitted to the atmosphere and that they are included in the main stack emission limit, an emissions limit has not been included as a separate requirement.

2.b.V.B.2.{OS} This subsection is for visible emissions monitoring from the main stack and the roof vents using method 9. This section is irrelevant because it is for equipment that has been removed or replaced when the "new –upgraded" smelter was constructed in 1994.

2.b.V.B.3.{OS} This subsection required the use of a CEM to demonstrate compliance with the Acid Plant SO2 limit. Subsection IX.H.1.f of the new maintenance plan covers the use of CEMs and opacity monitoring. This subsection is irrelevant.

2.b.V.B.4.{OS} Annual Emissions – established total annual emissions for the entire smelter. The Smelter operations have since been modified and upgraded thus making these emissions estimates irrelevant.

2.b.V.B.5.{OS} This subsection established an effective date for the smelter limits except for the three hour SO_2 limits. The effective date has already passed and therefore this subsection is

irrelevant.

2.b.V.B.6.{OS} This subsection established an effective date for the smelter SO_2 three hour average limits. The effective date has already passed and therefore this subsection is irrelevant.

Subsections 2.b.V.C.1 thru 2.b.V.C.7{OS} are for temporary conditions. These temporary conditions have already been met and therefore, this subsection is irrelevant.

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that

production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – Smelter Specific Requirements

IX.H.2.n.i.A This condition establishes limits for the Main stack, Acid Plant Tail Gas stack and the Holman boiler. The PM_{10} limits are based on a daily average. This protects the 24 hour PM_{10} standard. The Daily NO_x limit has been added to protects the 24 hour PM_{10} standard.

I. Main Stack (Stack No.11)

1. PM_{10}
   a. 89.5 lbs/hr (filterable, daily average)
   b. 434 lbs/hr (filterable + condensable, daily average)

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

3. NO_x
   a. 154 lbs/hr (daily average)

II. 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
      0.05 lbs/MMBTU, 30-day average

IX.H.2.n.i.B This condition establishes stack test frequencies for the Main Stack, Acid Plant and Holman boiler.

EMISSION POINT	POLLUTANT	TEST FREQUENCY
I. Main Stack (Stack No. 11)		
	PM_{10}	every year
	SO_2	CEM
	NO_x	CEM
II. Holman Boiler	NO_x	CEM or alternate method determined according to applicable NSPS standards

Currently the Holman boiler does not have a CEM and Kennecott uses an alternative monitoring plan to determine the NO_x emissions. Kennecott continuously monitors operational parameters to predict NO_x emissions and to ensure proper boiler operation. The parameters monitored are fuel use (to predict NO_x emissions lbs/hr), stack oxygen

(to monitor proper boiler operation and compliance with NO_x lbs/MMBtu emission limit), and steam output (used to estimate heat input if fuel use unavailable). The ranges for these parameters were developed during a 30-day monitoring campaign where data from a certified NO_x analyzer was used to develop predictive equations with the operational parameters. The alternative monitoring method identified in this condition is consistent with the applicable NSPS.

IX.H.2.n.i.C During startup/shutdown operations, NO_x and SO_2 emissions are monitored by CEMS or alternate methods in accordance with applicable NSPS standards.

5.1 Monitoring, Recordkeeping and Reporting

Monitoring for all three emission points is addressed through a variety of methods, depending on the emission point in question. Stack testing, CEMs, or alternative monitoring as allowed under NSPS Subpart Db – all are viable options, and have been included in the language of IX.H.2.n.i.b and IX.H.2.n.1.C. As appropriate, these monitoring requirements are complemented by the general provisions of IX.H: 1.e for stack testing, 1.f for CEMs and other continuous monitors, 1.c for recordkeeping and reporting.

5.2 Discussion of Attainment Demonstration

Generally, the calculation methodology for determination of emissions from the smelter is identical to the method used in during the 1991/1992 timeframe of the original SIP. However, several key differences exist:

1. Emissions in the new maintenance plan are lower or equal to the original SIP

Smelter emissions for PM_{10} and SO_2 are significantly lower than those in the original SIP. As discussed earlier in this document, KUC initiated a Smelter modernization project in the mid-1990s, thus constructing and now operating one of the cleanest copper smelters in the world.

2. Condensable emissions, which were excluded from the original SIP, are included in the new maintenance plan

The original SIP was based on filterable PM_{10} emissions only. The new maintenance plan includes both filterable and condensable PM_{10} emissions. The hourly PM_{10} limit listed in IX.H.2.n.1.A includes condensable emissions from several emission sources that emit to the Main Stack.

6.0 Implementation Schedule

The requirements imposed on the smelter are currently in effect. While some provision was made for sources generally to implement the RACT requirements of the PM2.5 SIP (and which were included as part of the modeled emission values for each source as discussed in that section above), the smelter did not have any required RACT modifications to undertake. The emission limits listed in IX.H.2.j can be applied immediately. Similarly, the provisions of IX.H.1.a-f (the General Requirements) can also be applied immediately.

7.0 References

- Kennecott Smelter, $PM_{2.5}$ SIP Major Point Source RACT Documentation
- UDSHW Contract No. 12601, Work Assignment No. 7, Utah $PM_{2.5}$ SIP RACT Support – TechLaw Inc.
- Smelter AO DAQE-AN103460054-14
- Smelter/Refinery Title V 3500030003

Evaluation Report – KUC Smelter

UTAH PM_{10} SIP/MAINTENANCE PLAN

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report: PacifiCorp Energy – Gadsby Power Plant

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM10 SIP/MAINTENANCE PLAN EVALUATION REPORT
PacifiCorp Energy – Gadsby Power Plant

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the Utah Implementation Plan (SIP); to address the Salt Lake County PM_{10} Nonattainment Area (SLCNA). This document specifically serves as an evaluation of the PacifiCorp Energy operated Gadsby Power Plant.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Sections IX.H.1-4 of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report.
- When referencing the original SIP with an effective date of August 8, 1994 the qualifier $^{\{OS\}}$ will follow any citation from that document.
- In reference to the updated Utah County SIP with an effective date of January 22, 2003 the qualifier $^{\{UC\}}$ will follow any citation from that document.
- When referencing any new Maintenance Plan/SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Gadsby Power Plant
Address: 1407 West North Temple (rear), Salt Lake City, Utah,
Salt Lake County
Owner/Operator: PacifiCorp Energy
UTM coordinates: 4,513,486 m Northing, 421,582 m Easting, Zone 12

1.2 Facility Process Summary

The Gadsby Power Plant (Gadsby) is a natural gas-fired electric generating plant consisting of three (3) steam boilers (Units #1, #2 and #3) and three (3) simple-cycle combustion turbines (Units #4, #5 and #6). Unit #1 is a 65 MW unit constructed in 1951, Unit #2 is an 80 MW unit constructed in 1952, and Unit #3 is a 105 MW unit constructed in 1955. Fuel oil may be used in Units #1, #2, and #3 as a back-up fuel during natural gas curtailments. Units #1 and #2 are equipped with low NOx burners. Units #4-6 are 43.5 MW LM6000 natural gas-fueled simple cycle combustion turbine engines that were added in 2002. The plant also has two small black start (emergency) generators (175 kW and 1,007 kW), three cooling towers for the boilers, and several small storage tanks.

1.3 Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

65 MW natural gas-fired steam boiler (diesel fuel capable) – Unit #1
80 MW natural gas-fired steam boiler (diesel fuel capable) – Unit #2
105 MW natural gas-fired steam boiler (diesel fuel capable) – Unit #3
43.5 MW LM6000 natural gas-fueled simple cycle gas turbine – Unit #4
43.5 MW LM6000 natural gas-fueled simple cycle gas turbine – Unit #5
43.5 MW LM6000 natural gas-fueled simple cycle gas turbine – Unit #6
175 kW diesel generator – Em Gen #1
1,007 kW diesel generator – Em Gen #2
Storage tanks (several tanks ranging in size from 975 gallons to 4,200 gallons)
Cooling Towers #1, #2, #3

1.4 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, Gadsby's baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	12.254
SO_2	0.809
NO_x	71.117

The current PTE values for Gadsby, as established by the most recent AO issued to the source (DAQE-AN103550015-09) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	114.27
SO_2	10.1
NO_x	726.8

However, please see Section 2.0 (and Table 3) below for further details on Gadsby's true PTE

value.

2.0 Modeled Emission Values

Unlike the base year inventory, which used only the 2011 actual emissions for each source to set the baseline for modeling, a modified version of the PTE values was used for the modeled attainment demonstration. Generally speaking, beginning with the PTE values listed in Table 2 (from the most recent approval order issued to each source), these values were "trued-up" by including the expected effects from implementation of RACT from the PM2.5 SIP. This yields a 2019 Projected Emission Value for each of the pollutants of concern. Where necessary, these values were corrected for condensable particulates using simple correction factors based on fuel consumed or process type.

Where gaseous fuels such as natural gas were combusted, filterable-only emissions were converted to a filterable+condensable emission value by multiplying the filterable rate by 4. For natural gas, AP-42 lists the various emission factors as:

Filterable PM: 1.9 lb/106 scf
Condensable PM: 5.7 lb/106 scf
Total PM: 7.6 lb/106 scf

In other words, the total PM is almost exactly four times the filterable emission value. Liquid fuels, such as diesel fuel #2, were also converted using the latest AP-42 emission factors. Processes such as cooling towers, which emit largely filterable-only emissions, were not adjusted. Other processes were adjusted, as needed, on a case-by-case basis using the best data available – primarily the latest stack test information.

For the Gadsby Plant only one of these steps was required. The most recent AO to this source was already adjusted for the effects of condensable PM10. When RACT was imposed as part of the requirements of the PM2.5 SIP, the Gadsby plant was only required to install extended catalyst beds on the SCR units controlling the natural gas-fired turbines. The total expected reduction in NOx emissions is about 10.7 tpy – yielding the following adjusted modeled PTE values (shown in Table 3 below):

Table 3: Modeled Emission Values

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	114.27
SO_2	10.1
NO_x	716.1

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent PM2.5 Section of the SIP. This Section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM10 SIP sources – including the Gadsby power plant. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11-13 – which comprise the PM2.5 sections of the SIP, and include this additional RACT application. All requirements from the original PM10 SIP that have not been superseded or replaced, and which are still necessary, will also be retained. By necessary, meaning: significant from the standpoint of PM10 control, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in

Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

Gadsby is a previously listed SIP source. In the original PM_{10}, Gadsby was listed in Subsection IX.H.2.b.BBB{OS} as Utah Power & Light - Gadsby. As a listed source there were several requirements and conditions that applied to the facility.

In addition, Gadsby is also a listed source in the PM2.5 Section of the SIP (see SIP Section IX.H.12.q). As was discussed above in Item 2.0, all limits in this maintenance plan are based on the limits in the December 3, 2014 PM2.5 SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.q. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below:

3.1 Original SIP General Requirements

IX.H.2.a General Requirements{OS}

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a{OS} applied to the listed sources found in Utah County, while those found at IX.H.2.a{OS} applied to the listed sources found in Salt Lake and Davis County. As the Gadsby power plant was (and is) located in Salt Lake County, only the general requirements of IX.H.2.a{OS} applied.

2.a.A. Stack Testing{OS} – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which serves the same purpose.

2.a.B. Visible Emissions{OS} – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which serves the same purpose.

2.a.C. Visible Emissions (cont.){OS} – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.D. Annual Emission Limitations{OS} – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists, and no source-specific annual SIP Caps appear in either IX.H.2 or IX.H.3 of the new maintenance plan.

2.a.E. Recordkeeping Requirements{OS} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders{OS} – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance{OS} – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program, under R307-401-4(1).

2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program, under R307-401-3(1)(b).

2a.I. Unpaved Operational Areas{OS} – established rules for treating fugitive dust with water sprays or chemical dust suppression. This requirement has been superseded by the fugitive dust rules of R307-205 and R307-1-4.5, or the most recent federally approved fugitive dust rule.

2.a.J. Actual Emissions{OS} – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsections IX.H.1-4 of the SIP. This requirement is outdated and obsolete.

2.a.K. Test if Directed{OS} – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions{OS} – established that the definitions contained in R307 apply to subsection IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.M. Petroleum Refineries{OS} – This is a fairly lengthy subsection pertaining only to the petroleum refineries. This subsection has its own sub-subsections, owing to the overall length and complexity. This subsection has been replaced generally by the new maintenance plan requirements found at IX.H.1.g; however, as this source is not a petroleum refinery, this subsection does not apply.

2.a.N. Specific Fuel Requirements for Coal and/or Oil{OS} – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded by the individual source requirements found in IX.H.2 and IX.H.3 (see specifically the sources Kennecott and BYU). This requirement is now largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources have the ability to burn any other fuel oils.

3.3 Original SIP Source Specific Requirements

Individual source requirements:

2.b.BBB.1.{OS} This subsection was a listing of the equipment at the power plant – this subsection has been superseded and is irrelevant. A simple listing of equipment does not constitute an emission limitation, does not impose any restriction on daily emissions, and rapidly becomes out of date as well as impossible to enforce. The original listing found in this subsection does not match the current equipment installed and operating at the plant and would represent a significant step backwards in emission control and power generation technology.

2.b.BBB.2.{OS} Emissions limitations on the three boilers. Two different sets of NOx emission limits were established: one set for "winter-time" operation, defined as being from November 1 through the end of February; the second being "summer-time" operation, defined as March 1, through October 31. This condition has been split and moved into three separate subsections of the new maintenance plan – specifically requirements IX.H.2.j.i.A, IX.H.2.j.ii.A, and IX.H.2.j.iii.A. These individual requirements retain the previous NOx limits on each of the three boilers.

2.b.BBB.3.{OS} Stack testing requirements. Established the specific stack testing method and frequency to demonstrate compliance with the emissions listed in the previous condition [2.b.BBB.2.{OS}]. This testing requirement has been superseded by IX.H.2.j.i.B, IX.H.2.j.ii.B, and IX.H.2.j.iii.B in the new maintenance plan which requires the installation and operation of NOx and O2 CEMs.

2.b.BBB.4.{OS} Fuel usage requirement. This condition limited the fuel types available for use in the boilers; requiring natural gas as primary, and #2 fuel oil or better only as a backup fuel. The sulfur content of any fuel oil burned was required to be tested, and fuel oil could only be used for maintenance firings, or during natural gas curtailments. Maintenance firings could only be scheduled between April 1, and November 30. Finally, records of fuel oil usage would be kept.

The three boilers are still dual-fueled; however, many of the specifics from the original SIP have been dropped as they are no longer necessary. The rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel (*see also* Item 2.a.N{OS} above for more details). Therefore only the specific requirement to burn natural gas except during natural gas curtailments has been retained. This requirement is now found at IX.H.2.j.iv.

2.b.BBB.5.{OS} Establishment of annual emissions. This subsection listed the expected values for PM10, NOx and SO2 for the power plant. It also stated that these values superseded the emissions previously credited to the source in an earlier letter dated February 7, 1986. Finally, it stated that these values were only valid if the boilers were capable of operation at the time of SIP approval.

This subsection is no longer valid as none of the original SIP annual values are applicable to the source at this time. The Gadsby Plant has expanded in operation by adding three combustion turbines with associated cooling towers. The original boilers are still in operation, but at reduced firing from full base load capacity.

Table 4 shows a comparison of the original SIP emission values, to the new maintenance plan expected emission rates. While the original SIP established annual values for each of the three pollutants, the new maintenance plan includes only direct short-term emission limits on NOx. Thus, the table includes a calculated 24-hr value of NOx emissions, based on multiplying the short term emission rates by the number of hours of operation (24 hours per day). As there are no short term limits established for PM10 or SO2, estimates of annual emissions are provided merely for comparison with the original SIP values. An estimate of annual NOx emissions is also provided for the same reason. All "new" annual emissions are taken from the latest permit issued to Gadsby. For comparison purposes, the estimate of daily NOx emissions from the original SIP was determined by simply dividing the annual value by 365 days. This provides a value which can be used to compare with the new maintenance plan, but serves no other useful purpose.

Table 4: Comparison Table – Old SIP Emissions vs New Maintenance Plan Emissions

All values in tons	SO_2 Original	SO_2 New	NO_x Original	NO_x New	PM_{10} Original	PM_{10} New
Annual	67.7	10.1	2,983.0	716.1	61.3[$]	114.27[&]
Daily (24-hr)	-	-	8.17[*]	7.3	-	-

[$] filterable emissions only
[&] includes condensable emissions and particulate emissions from three cooling towers
[*] estimate of daily emissions provided for comparison purposes only

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference. As specifically stated in subsection IX.H.1.a below, these general requirements apply to all sources subsequently listed in either IX.H.2 (Salt Lake County) or IX.H.3 (Utah County), and are in addition to (and in most cases supplemental to) any source-specific requirements found within those two subsections.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is

the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation. All conditions in these subsections are strictly in accordance with EPA approved methods and guidelines.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow in the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no

argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – Gadsby Specific Requirements

The Gadsby specific conditions in Section IX.H.2 address those limitations and requirements that apply only to the Gadsby Power Plant in particular.

IX.H.2.j.i This condition lists the specific requirements applicable to Steam Generating Unit #1 (Boiler #1).

Subparagraph A: NOx limit of 179 lbs/hr.
Subparagraph B: requirement to install and operate a NOx and CO2 CEM to demonstrate compliance with the emission limit in IX.H.2.j.i.A.

IX.H.2.j.ii This condition lists the specific requirements applicable to Steam Generating Unit #2 (Boiler #2).

Subparagraph A: NOx limit of 204 lbs/hr.
Subparagraph B: requirement to install and operate a NOx and CO2 CEM to demonstrate compliance with the emission limit in IX.H.2.j.ii.A.

IX.H.2.j.iii This condition lists the specific requirements applicable to Steam Generating Unit #3 (Boiler #3).

Subparagraph A.1: NOx limit of 142 lbs/hr, applicable between November 1 and February 28/29
Subparagraph A.2: NOx limit of 203 lbs/hr, applicable between March 1 and October 31
Subparagraph B: requirement to install and operate a NOx and CO2 CEM to demonstrate compliance with the emission limit in IX.H.2.j.iii.A.

IX.H.2.j.iv This condition lists the fuel requirement applicable to all three boilers.

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

IX.H.2.j.v This condition lists the requirements applicable to all three combustion turbines.

Subparagraph A: Total emissions of NOx from all three turbines shall be no greater than 600 lbs/day. For purposes of this subsection a “day” is defined as a period of 24-hours commencing at midnight and ending at the following midnight.
Subparagraph B: requirement to install and operate a NOx and O2 CEM to demonstrate compliance with the emission limit in IX.H.2.j.v.A.

IX.H.2.j.v This condition lists the startup/shutdown emission minimization plan requirements applicable to all three combustion turbines. The requirement also includes a definition of startup, shutdown, and a limit on total hours of operation (2) in startup or shutdown mode, per turbine, per day. This condition also

includes the requirement to monitor power output as a measurement of turbine load (required under subparagraphs B and C of the condition) through installation of a power meter.

5.1 Monitoring, Recordkeeping and Reporting

Monitoring for IX.H.2.j.i.A is specifically outlined in IX.H.2.j.i.B; IX.H.2.j.ii.A is addressed in IX.H.2.j.ii.B; etc. All NOx monitoring is covered by CEM. CEM monitoring requirements are found in IX.H.1.f. Recordkeeping is subject to the requirements of IX.H.1.c.

5.2 Discussion of Attainment Demonstration

Both in the original SIP and in the new maintenance plan, Gadsby was primarily a source of NOx emissions. While some direct PM10 and SO2 emissions added to the overall contribution from Gadsby, it remains a listed source because of NOx. Total emissions of NOx have dropped from 2,983 tons per year in the original SIP to an estimated 716.1 tons in the new maintenance plan. While direct PM10 emissions have increased slightly, this is due primarily to the contribution of condensable particulates, which were not included in the original SIP. Some direct PM10 is also provided from the new cooling towers. Emissions of SO2 have remained roughly equal.

6.0 Implementation Schedule

For the most part, the requirements imposed on the Gadsby Power Plant are effective immediately. While some provision was made for sources generally to implement the RACT requirements of the PM2.5 SIP (and which were included as part of the modeled emission values for each source as discussed in that section above), the Gadsby plant has already completed all required RACT modifications. The emission limits listed in IX.H.2.j can be applied immediately. Similarly, the provisions of IX.H.1.a-f (the General Requirements) can also be applied immediately.

7.0 References

Evaluation Report – Gadsby Power Plant

UTAH PM_{10} SIP/MAINTENANCE PLAN

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report: Tesoro Refining & Marketing Company LLC

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
Tesoro Refinery

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the Utah Implementation Plan (SIP); to address the Salt Lake County PM_{10} Nonattainment Area (SLCNA). This document specifically serves as an evaluation of the Tesoro Refinery.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Sections IX.H.1-4 of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report. However, see Section 7.0 of this document for some clarification.
- When referencing the original SIP with an effective date of August 8, 1994 the qualifier $^{\{OS\}}$ will follow any citation from that document.
- In reference to the updated Utah County SIP with an effective date of January 22, 2003 the qualifier $^{\{UC\}}$ will follow any citation from that document.
- When referencing any new Maintenance Plan/SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Tesoro Salt Lake City Refinery
Address: 474 West 900 North, Salt Lake City, Utah, Salt Lake County
Owner/Operator: Tesoro Refining & Marketing Company
UTM coordinates: 4,515,950 m Northing, 423,400 m Easting, Zone 12

1.2 Facility Process Summary

The Tesoro Refinery is a petroleum refinery capable of processing 57,500 barrels per day of crude oil. The source consists of a FCCU, catalytic reforming unit, hydrotreating units, a sulfur recovery unit, and cogeneration units. The source also has the usual assorted heaters, boilers, cooling towers, storage tanks, flares, and fugitive emissions. The source does not operate with flare gas recovery.

1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of the main emitting units from the Tesoro Refinery:

Crude Unit Furnace, with ultra-low NOx burners
Ultraformer Unit (UFU) Furnace, with low NOx burners
UFU Regeneration Heater, with low NOx burners
Fluid catalytic Cracking Unit (FCCU), Carbon Monoxide Boiler (Heat Recovery Unit), with CONOx oxygen injection, ammonia injection, electrostatic precipitator (ESP)
Distillate Desulfurization Unit (DDU) charge heater and rerun boiler, combined rating approx. 37.8 MMBtu/hr, equipped with “ultra-ultra” low-NOx burners
Hydrogen Compressors (Ultraformer compressors), with catalytic converters
South Flare (Flare covering Crude/UFU Unit/DDU)
North Flare (Flare covering FCCU/VRU/Alkylation Unit/GHT)
Sulfur Recovery Unit/Tail Gas Incinerator/Tail Gas Treatment Unit
Fuel Gas Desulfurization Unit/Sour Water Stripper (FGDU/SWS) Flare (this unit is physically integrated with the Sulfur Recovery Unit (SRU))
Emergency/Standby Sources
Waste Water Treatment Plant (WWTP) Generator
Electrical Generators
Plant Air Compressors
Miscellaneous Air Compressors
Fire Water Pumps
B-1 Air Preheater
Package Boilers
Gasoline Hydrotreater (GHT) Unit with 8.0 MMBtu/hr process heater
Benzene Saturation Unit (BSU): 3,000 bpd Bensat reactor and 10,000 bpd reformate splitter
Two cogeneration turbines (CG1 and CG2), 11.8 MW each with SoLoNOx, and heat recovery steam generating units (HRSG) rated at approx. 157.8 MMBtu/hr
Loading/Unloading Racks
Cooling Towers
Fugitives
Tank Farm

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at the refinery, rather it is a listing of all significant emission units or emission unit groups (such as the tank farm).

1.4 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, Tesoro's baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	126.07
SO_2	795.31
NO_x	383.73

The current PTE values for Tesoro, as established by the most recent AO issued to the source (DAQE-AN103350065-14) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	282.0
SO_2	1637.0
NO_x	638.0

However, please see Section 2.0 (and Table 3) below for further details on Tesoro's true PTE value.

2.0 Modeled Emission Values

Unlike the base year inventory, which used only the 2011 actual emissions for each source to set the baseline for modeling, a modified version of the PTE values was used for the modeled attainment demonstration. Beginning with the PTE values listed in Table 2 (from the most recent approval order issued to Tesoro in 2014), these emissions were then "trued-up" by including the expected effects from implementation of RACT from the $PM_{2.5}$ SIP. This true-up yields a 2019 Projected Emission Value for each of the pollutants of concern. Where necessary, these values were further corrected for condensable particulates using simple correction factors based on fuel consumed or process type.

Where gaseous fuels, such as natural gas or refinery fuel gas, were combusted, filterable-only emissions were converted to a filterable+condensable emission value by multiplying the filterable rate by 4 (see explanation in section 3.3 of this document under the subheading of "Basis for the PM_{10} Emission Limitations"). Liquid fuels, such as diesel fuel #2, were converted using the latest AP-42 emission factors. Processes such as cooling towers, which emit largely filterable-only emissions, were not adjusted. Other processes were adjusted, as needed, on a case-by-case basis using the best data available – primarily the latest stack test information.

For the Tesoro Refinery, this yielded the following modeled emission values – summarized in Table 3.

Table 3: Modeled Emission Values

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	559.38
SO_2	300.0
NO_x	475.0

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the December 3, 2014 $PM_{2.5}$ Section of the SIP (IX.H.11-13). This section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM_{10} SIP sources – including the refineries in general, and the Tesoro Refinery in specific. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11-13 – which comprise the $PM_{2.5}$ sections of the SIP, and include this additional RACT application. All requirements from the original PM_{10} SIP that have not been superseded or replaced, and which are still necessary, will also be retained. By necessary, meaning: significant from the standpoint of PM_{10} control, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

Tesoro is a previously listed SIP source. In the original PM_{10}, Tesoro was listed in Subsection IX.H.2.b.A$^{\{OS\}}$ as Amoco Oil Company. As a listed source there were several requirements and conditions that applied to the facility.

In addition, Tesoro is also a listed source in the PM2.5 Section of the SIP (see SIP Section IX.H.12.r). As was discussed above in Item 2.0, all limits in this maintenance plan are based on the limits in the December 3, 2014 $PM_{2.5}$ SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.r. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below:

3.1 Original SIP General Requirements

IX.H.2.a General Requirements$^{\{OS\}}$

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a$^{\{OS\}}$ applied to the listed sources found in Utah County, while those found at IX.H.2.a$^{\{OS\}}$ applied to the listed sources found in Salt Lake and Davis County. As the then Amoco Refinery was located in Salt Lake County, only the general requirements of IX.H.2.a$^{\{OS\}}$ applied. However, except for the additional requirements found under IX.H.2.a.M$^{\{OS\}}$ for petroleum refineries and the specific fuel requirements of IX.H.2.a.N$^{\{OS\}}$, the two subsections are essentially identical.

2.a.A. Stack Testing$^{\{OS\}}$ – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which serves the same purpose.

2.a.B. Visible Emissions$^{\{OS\}}$ – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which serves the same purpose.

2.a.C. Visible Emissions (cont.)$^{\{OS\}}$ – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.D. Annual Emission Limitations$^{\{OS\}}$ – established that annual emissions would be determined

on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists, and no source-specific annual SIP Caps appear in either IX.H.2 or IX.H.3 of the new maintenance plan.

2.a.E. Recordkeeping Requirements{OS} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders{OS} – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance{OS} – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program, under R307-401-4(1).

2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program, under R307-401-3(1)(b).

2a.I. Unpaved Operational Areas{OS} – established rules for treating fugitive dust with water sprays or chemical dust suppression. This requirement has been superseded by the fugitive dust rules of R307-205 and R307-1-4.5, or the most recent federally approved fugitive dust rule.

2.a.J. Actual Emissions{OS} – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsections IX.H.1-4 of the SIP. This requirement is outdated and obsolete.

2.a.K. Test if Directed{OS} – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions{OS} – established that the definitions contained in R307 apply to subsection IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.N. Specific Fuel Requirements for Coal and/or Oil{OS} – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded by the individual source requirements found in IX.H.2 and IX.H.3 (see specifically the sources Kennecott and BYU). This requirement is now largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources have the ability to burn any other fuel oils.

3.2 Original SIP Petroleum Refinery Requirements

2.a.M. Petroleum Refineries{OS} – This is a fairly lengthy subsection pertaining only to the

petroleum refineries. This subsection has its own sub-subsections, owing to the overall length and complexity.

2.a.M.A. Sulfur Recovery Units (SRUs)$^{\{OS\}}$ – established the requirement for 95% efficient SRUs, no burning of liquid fuel oil except during natural gas curtailments, use of low-SO_x catalyst to attain a 9.8 kg SO_2/1000 kg coke burnoff in FCC units, amine and sour water overhead streams shall also be processed in the SRU. These conditions currently remain in effect. The SO_2 limit is largely irrelevant as the limitation in SIP subsection IX.H.1.g.i.A.I is based on 40 CFR 60, Subpart Ja, and is more stringent. The other three requirements: 95% efficient SRUs, no burning of liquid fuel oil, & amine and sour water overhead streams being processed in the SRU, shall be retained. These three conditions are found at SIP subsections IX.H.1.g.iii, IX.H.1.g.iv, and IX.H.1.g.iii, respectively.

2.a.M.B. Routine Turnaround Periods$^{\{OS\}}$ – established exclusion periods when routine turnarounds of the SRUs could be performed, and the procedure for scheduling one of these periods. These conditions are no longer required. Each of the refineries has agreed to incorporate alterative language which supersedes these requirements. In Tesoro's specific case, the refinery has opted to simply include SRU turnaround emissions within the existing 24-hour emission Caps – including all flaring and additional SO_2.

2.a.M.C.1. Compliance Demonstration part 1$^{\{OS\}}$ – established that SRU turnaround emissions and flaring emissions are not included in either the daily (24-hour) or annual compliance demonstrations. As with 2.a.M.B$^{\{OS\}}$ above, this requirement is no longer required. Each refinery has agreed to alternative language regarding SRU turnarounds. All flaring emissions have been included in both the annual and 24-hour emission Caps for each listed refinery.

2.a.M.C.2. Compliance Demonstration part 2$^{\{OS\}}$ – established how the daily (24-hr) emissions limits (Caps) would be determined, including recordkeeping and reporting requirements. This subsection has since been superseded by the individual source's SIP subsection (for Tesoro, this would be Section IX.H.2.k) which establishes the 24-hour emission limits, and the monitoring, recordkeeping and reporting requirements associated with those limits.

2.a.M.C.3. Compliance Demonstration part 3$^{\{OS\}}$ – established a methodology for how emission limits could be modified/adjusted as necessary. This subsection is no longer required, as this procedure is no longer followed.

2.a.M.C.4. Compliance Demonstration part 4$^{\{OS\}}$ – also established that annual emissions for refineries followed a process essentially identical to the rolling 12-month process outlined above in 2.a.D$^{\{OS\}}$. This subsection is no longer required as the specific requirement to track annual emissions is no longer needed with the removal of the annual PM10 standard.

2.a.M.D. Process Flaring Emissions and Routine Turnaround Emissions$^{\{OS\}}$ – established that both sets of emissions were included in the modeled attainment demonstration. This subsection is no longer required, as a new attainment demonstration has been performed and both process flaring and routine turnaround emissions are handled differently in the new maintenance plan. See SIP subsection IX.H.1.g.v.B which covers flare gas recovery systems. SRU routine turnarounds requirements have been removed from the new maintenance plan.

3.3 Original SIP Source Specific Requirements

Individual source requirements:

2.b.A.1.{OS} This subsection was a listing of the equipment at the refinery – this subsection has been superseded and is irrelevant. A simple listing of equipment does not constitute an emission limitation, does not impose any restriction on daily emissions, and rapidly becomes out of date as well as impossible to enforce. The original listing found in this subsection does not match the current equipment installed and operating at the refinery and would represent a significant step backwards in emission control and refining technology.

2.b.A.2.{OS} Basis for SO_2 Emission Limitations – A) established the SO_2 daily and annual emission Caps. There were two daily Caps: a smaller "wintertime" Cap which ran from November 1 through the last day of February, and a larger Cap for the remainder of the year. There was only a single annual Cap. B) established the sources included in the SO_2 emissions Caps. Although [2.b.A.2.A){OS}] also included a "plant-wide" emission value, this value was based on the emissions from specific "Cap sources" which were listed in this subsection. C) established that the SO_2 emission Caps shall be determined by multiplying the amount of each type of fuel burned each day by specific emission factors listed in this subsection [2.B.A.2.C){OS}.]. The equations to be used, and the compliance methodology for various processes or fuel types was listed. This subsection also established SO2 monitoring and recordkeeping provisions. D) established individual point source limitations for the SRU incinerator. E) established that stack testing would be performed as outlined in SIP subsections 2.b.A.5{OS}, 2.a.A{OS} and 2.a.M{OS}. F) established that the flares were not included in the SO_2 Caps, and also not regulated for SO_2 emissions.

This subsection has since been superseded by the SIP subsection which establishes new plantwide SO_2 daily (24-hour) emission Caps (for Tesoro, this would be Section IX.H.2.k.iii). These new SO_2 emission Caps cover all emission units at the refinery – including the flares – so no emission unit is excluded. The new SO_2 emission Caps are significantly lower than the original Caps (although the annual standard no longer exists, Table 4 below includes the expected annual emission values for each of the three pollutants as a convenient comparison with the original SIP emissions). The compliance methodology included in SIP subsection IX.H.2.k.iii also includes the calculation of amount of fuel burned multiplied by the emission factor for each fuel type – although these emission factors have been updated as needed. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below). Finally, in addition to the flares being included in the SO_2 emission Caps, they are also addressed under SIP subsection IX.H.1.g.v.B which covers flare gas recovery systems.

2.b.A.3.{OS} Basis for the NO_x Emission Limitations – Similar to the SO_2 limitations above: A) established the NO_x daily and annual emission Caps. Only a single daily NOx Cap was established. However, both the daily and annual emission Caps were not plant-wide and included only the emission sources listed in the next subsection. B) established the sources included in the NO_x emissions Caps. This subsection also listed default emission factors to be used for compliance determination. C) established that compliance with the NO_x emission Caps shall be determined by multiplying the amount of each type of fuel burned each day by the specific emission factors listed in the previous subsection [2.b.A.3.B){OS}]. D) established that total 24-hour emissions would be calculated as in the previous subsection [2.b.A.3.C){OS}]and then summed for all emission Cap sources. Results would be tabulated every day, and records would be kept of all appropriate parameters as well as calculated emissions. E) established that stack testing would be performed as outlined in SIP subsections 2.b.A.5{OS}, 2.a.A{OS} and 2.a.M{OS}.

F) established that the flares were not included in the NO_x Caps, and also not regulated for NO_x emissions.

This subsection has since been superseded by SIP subsection IX.H.2.k.ii which establishes new plantwide NO_x daily (24-hour) emission Caps. As with the SO_2 emission Caps, these new NO_x emission Caps cover all emission units at the refinery – including the flares. The new NO_x emission Caps are also lower than the original Caps. As with SO2, annual values have been included in Table 4 for comparison purposes. Again, the compliance methodology included in SIP subsection IX.H.2.k.ii uses the amount of fuel burned multiplied by the emission factor for each fuel type. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below).

2.b.A.4.{OS} Basis for the PM_{10} Emission Limitations – As with both the SO_2 and NO_x limitations listed above: A) established the PM_{10} daily and annual emission Caps. B) established the sources included in the PM_{10} emissions Caps. C) established that the PM_{10} emission Caps shall be determined by multiplying the amount of each type of fuel burned each day by specific emission factors listed in this subsection [2.B.A.3.C){OS}.]. The equations to be used, and the compliance methodology for various processes or fuel types was listed. This subsection also established PM10 monitoring and recordkeeping provisions. D) established that the flares, the ultraformer compressor and the SRU incinerator were not included in the PM_{10} Caps, and also not regulated for PM_{10} emissions.

This subsection has since been superseded by SIP subsection IX.H.2.k.i which establishes new plantwide PM_{10} daily (24-hour) emission Caps. As with both the SO_2 and NO_x emission Caps, these new PM_{10} emission Caps cover all emission units at the refinery – including the flares. The annual values are also listed for ease of comparison. As before, the compliance methodology included in SIP subsection IX.H.2.k.i uses the amount of fuel burned multiplied by the emission factor for each fuel type. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below).

Table 4: Comparison Table – Old SIP Caps vs New SIP Caps

	SO_2 Original	**SO_2 New**	**NO_x Original**	**NO_x New**	**PM_{10} Original**	**PM_{10} New**
Annual	1964.0	300.0	-	475.0	-	559.38[&]
Annual (Cap Sources)	1370.0	-	638.0	-	113[$]	-
Daily (24-hr)	7.264 / 6.296[*]	3.1	-	1.988	-	2.14[&]
Daily (Cap Sources)	5.067 / 4.392[*]	-	2.098	-	0.310[$]	-

[*] Values listed are Mar. 1 through Oct. 31 / Nov. 1 through Feb 28/29
[$] filterable emissions only
[&] includes condensable emissions

The new PM10 values for Tesoro listed in Table 4 above appear to be significantly larger than the original SIP emissions for the Amoco Refinery. However, two factors need to be taken into account. The first is the difference between including only emission Cap sources in the emission total, and making the total "plant-wide" (as is the case in the new maintenance plan). The second,

far more significant difference, is the one between filterable-only emissions and condensable emissions. The combustion of gaseous fuels like natural gas or refinery fuel gas have vastly different emission factors for filterable and condensable particulate emissions. For natural gas, AP-42 lists the various emission factors as:

Filterable PM: 1.9 lb/10^6 scf
Condensable PM: 5.7 lb/10^6 scf
Total PM: 7.6 lb/10^6 scf

In recent stack tests, the emission factors for refinery fuel gas were found to be equivalent to natural gas. In other words, the total PM is almost exactly four times the filterable emission value. When these two factors are taken together, the PM10 emissions at the Tesoro refinery remain essentially unchanged from the values listed in the original SIP.

2.b.A.5.{OS} Stack Testing Requirements – established which point sources were required to comply with specific emission limitations (established in preceding paragraphs), the test method to be used to verify compliance (including CEMs if applicable), and the frequency of testing and/or monitoring.

This subsection has since been superseded by SIP subsection IX.H.2.k which establishes new monitoring, recordkeeping and reporting requirements for each of the limits listed in that subsection. The test methods to be used for each specific pollutant are listed in subsection IX.H.1.c. While details on the use of CEMs is covered in subsection IX.H.1.f.

2.b.A.6.{OS} Annual Emissions – established total annual emissions for the entire refinery. These annual emissions differed from the SIP Cap totals in one important aspect; the SO_2 total included values for SRU turnaround emissions (393 tpy). Thus, total annual SO_2 emissions were established at 2,357 tons/yr.

This subsection has since been superseded by SIP subsections IX.H.2.k.i, IX.H.2.k.ii and IX.H.2.k.iii which establishes new emission Caps for each of the pollutants of concern (PM_{10}, NO_x and SO_2). These emission Caps include the potential emissions from all emission units at the refinery, including the flares.

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference. As specifically stated in subsection IX.H.1.a below, these general requirements apply to all sources subsequently listed in either IX.H.2 (Salt Lake County) or IX.H.3 (Utah County), and are in addition to (and in most cases supplemental to) any source-specific requirements found within those two subsections.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to

IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves.

Rather, they outline the scope of the conditions which follow – either in the Petroleum Refinery provisions of IX.H.1.g, or the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – General Refinery Requirements

The new maintenance plan will incorporate several new requirements that apply specifically to those petroleum refineries listed in Sections IX.H.2 and IX.H.3 of the SIP. Some subsections of IX.H.1.g also apply more broadly and could affect additional petroleum refineries in addition to those listed in the Source Specific sections which follow. Where this greater applicability exists for a particular condition or limitation, such will be noted in the discussion for that requirement.

IX.H.1.g.i.A This condition covers SO_2 emissions from fluidized catalytic cracking units (FCCUs). The limit is 50 ppmvd @ 0% excess air on a 7-day rolling average basis, as well as 25 ppmvd @ 0% excess air on a 365-day rolling average basis.

The condition is based on 40 CFR 60 Subpart Ja, and includes the same limitation found in that subpart. Compliance is demonstrated by CEM, as outlined in 40 CFR 60.105a(g) – also from Subpart Ja.

IX.H.1.g.i.B This condition addresses PM emissions from FCCUs. The limit is 1.0 lb PM per 1000 lb coke burned. The emission limit applies on a 3-hour average basis.

The emission limit is derived from 40 CFR 60 Subpart Ja, although Subpart Ja does not specifically state that the limit applies on a 3-hour average. Instead it states that compliance will be demonstrated via a performance test using Method 5, 5b or 5f, using an average of three 60-minute (minimum) test runs.

Compliance is demonstrated by stack test as outlined in 40 CFR 60.106(b). This stack testing procedure is from Subpart J, rather than Subpart Ja. The equations utilized and reference methods involved are identical between the two subparts; however, the protocol to follow for testing is much more direct and straightforward in §60.106(b). The condition also requires the installation of a continuous parameter monitoring system (CPMS) to monitor and record

operating parameters for determination of source-wide PM_{10} emissions for inclusion in the 24-hour PM_{10} Cap (see the individual source specific requirements of IX.H.2 for details on these Caps).

IX.H.1.g.ii This condition limits the H_2S content of gases burned within any refinery located within (or affecting) an area of $PM_{2.5}$ nonattainment. The limit is 60 ppm H_2S or less as described in 40 CFR 60.102a on a rolling average of 365 days.

As the $PM_{2.5}$ nonattainment areas encompasses the entirety of the PM_{10} maintenance areas this condition potentially affects more than just the four refineries listed in IX.H.2. There is at least one minor source refinery (Silver Eagle Refinery) which is affected by this requirement. The Silver Eagle Refinery was previously listed in the original SIP as Crysen Refining, Inc., but was delisted as the source is no longer a major source.

Compliance is demonstrated through continuous H_2S monitoring, as outlined in 40 CFR 60.107a. Both the limitation and the compliance methodology are based on 40 CFR 60 Subpart Ja.

IX.H.1.g.iii This condition requires the installation of SRUs that are 95% effective in removing sulfur from the streams fed to the unit; or SRUs that meet the SO2 emission requirements of Subpart Ja. The amine acid gas and sour water stripper acid gas shall be processed in the SRU(s).

This is part of condition 2.a.M.A$^{\{OS\}}$ brought forward from the original SIP. No other requirement has specifically superseded this condition, so the language has been incorporated herein.

Compliance shall be demonstrated by daily monitoring of flows to the SRUs (flow rate) and SO2 concentration in the exhaust stream (via CEM). Compliance shall be determined on a rolling 30-day average. As the specific compliance methodology was never outlined in the original SIP condition, and not clarified in any of the original specific source requirements, this requirement attempts to address this deficiency.

Small changes in the language of this condition were made to accommodate differences between the various refineries as they exist today, and to clarify the original intent of the requirement. For cases where a refinery has combined exhaust flows for control purposes, this can make monitoring of the SO2 concentration from only the SRU exhaust highly difficult. However, past testing has demonstrated that a 95% level of control across the SRU results in SO2 emissions in excess of the Subpart Ja emission standard. Therefore, meeting the NSPS emission standard will represent an equivalent or greater level of control. Smaller refineries, without tail gas incineration and not currently subject to Subpart Ja, are still subject to the existing minimum 95% level of efficiency. With respect to the amine acid gas and sour water stripper gas, this new language clarifies that it is the acid gas from these two processes that needs to be sent to the SRU, not all potential streams – some of which may be liquid streams which cannot be handled by the SRU.

IX.H.1.g.iv This condition disallows the burning of liquid fuel oil except during natural gas curtailments and/or as specified in IX.H.2 or IX.H.3.

This is an additional part of condition 2.a.M.A$^{\{OS\}}$ brought forward from the original SIP. As with the SRU requirement addressed in the previous condition, this condition was also never superseded. The language has been incorporated herein. Specifically disallows the burning of fuel oil in refinery heaters and boilers. Specific language in the individual source requirements of

IX.H.2 (and potentially IX.H.3) allows for the use of diesel-fired emergency generators and similar emergency use equipment outside of natural gas curtailment periods.

IX.H.1.g.v This condition establishes new requirements on hydrocarbon flares.

It states that all hydrocarbon flares (defined as all non-dedicated SRU flare and header systems and all non-HF flare and header systems) are subject to Subpart Ja as of January 1, 2018 if not previously subject.

This is a simple requirement to set all the hydrocarbon flares as being subject to 40 CFR 60 Subpart Ja. It is language brought forward from the requirements of the PM2.5 SIP (Section IX.H.11.g.v.A) in order to maintain consistency between sections. Although the second paragraph of the PM2.5 SIP (IX.H.11.g.v.B) was not similarly brought forward, flare gas monitoring provisions which address the elements of that subsection can be found within each refinery's individual specific requirements of Section IX.H.2 (*see* Item 6.1 below).

5.1 Monitoring, Recordkeeping and Reporting

The new petroleum refinery requirements establish several specific emission limitations. Primarily these limits are monitored continuously – such as the SO_2 CEM on the FCCU or the H_2S monitor on fuel gas. Where continuous monitoring is used, the requirements of IX.H.1.f apply, which incorporates by reference R307-170, 40 CFR 60.13 and 40 CFR 60, Appendix B – Performance Specifications.

Under R307-170, paragraph 170-8 addresses Recordkeeping, while 170-9 addresses Reporting.

The FCCU PM limit is demonstrated by stack test. This stack test requirement is subject to the requirements of IX.H.1.e. In addition, any source with a direct stack emission limitation is subject to the requirements of R307-165.

These conditions are also subject to the general recordkeeping and reporting requirements of IX.H.1.c.

5.2 Discussion of Attainment Demonstration

PM Discussion: While the new PM limit on the FCCU might not appear to directly affect PM10 emissions, this would be incorrect. The limit is derived from the current NSPS (Subpart Ja). Under the NSPS, the assumption was that all particulate captured in the reference test method (Method 5, 5b or 5f) would be considered as PM10. This is still the case, as compliance with the PM limit at the FCCU shall be demonstrated by stack test. Using a method 5 variant stack test allows the test to be overly conservative, as some particulate captured may fall outside the PM10 size range, and still be useful for SIP planning purposes. At the same time, it lowers the regulatory burden on the sources, by allowing each source to only have to comply with the requirements of the individual NSPS. The limit is expressed on a 3-hour block average, well below the 24-hour basis of the PM10 standard. Stack tests are required every three (3) years, which meets the minimum stack test frequency set by DAQ. Compliance is demonstrated via monitoring and use of emission factors. Stack testing serves to periodically adjust emission factors to account for significant changes in feedstocks, refinery turnarounds, or other large-scale changes that would affect the emission factor. As allowed under R307-165-2, the Director may require stack testing at any time to demonstrate compliance.

SO_2 Discussion: This is a new limitation that did not previously appear in any form in the original SIP. Although the limit is expressed on a 7-day rolling average basis, and therefore longer than the 24-hour PM_{10} standard, SO_2 emissions are eventually converted into sulfates – the particulate form. As this process takes some time to occur, and is not directly dependent on hourly or daily SO2 emissions – but rather on area average SO2 concentrations and relative chemistry – a 7-day rolling average is quite adequate to demonstrate attainment with the standard. This is especially true, given the overall daily SIP Cap – which still controls total SO2 emissions from the entire refinery. The secondary limit, expressed on a 365-day basis simply serves to keep SO2 emissions down over the long run, as well as maintaining consistency with the PM2.5 SIP requirements.

H_2S Discussion: Although the limit appears to be on a much longer averaging period than the 24-hour PM_{10} standard, the rolling 365-day calculation prevents the overall H_2S content from increasing. This in turn keeps the amount of sulfur being sent to each fuel burning device consistently low. This is also a fallback limit, like the SO2 emissions from the FCCU discussed in the previous paragraph. Total SO2 emissions are still controlled by the daily SIP Cap, regardless of the averaging period on fuel gas H2S content.

6.0 New Maintenance Plan – Tesoro Specific Requirements

The Tesoro specific conditions in Section IX.H.2 address those limitations and requirements that apply only to the Tesoro Refinery in particular.

IX.H.2.k.i This condition establishes a source-wide Cap on PM_{10} emissions on a ton per day basis. Emissions are calculated on a filterable plus condensable basis from all sources, each day. This limit is 2.14 tons PM_{10} per day.

The condition also includes the definition of a day as being from midnight until the following midnight. Compliance 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. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.2.k.ii This condition establishes a source-wide Cap on NO_x emissions on a ton per day basis. Emissions are calculated from all emission points daily. This limit is 1.988 tons NO_x per day.

This condition includes the same definition of "day" as being from midnight until the following midnight. Compliance 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. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.2.k.iii This condition establishes a source-wide Cap on SO_2 emissions on a ton per day basis. Emissions are calculated from all emission points daily. This limit is 3.1 tons SO_2 per day.

This condition includes the same definition of "day" as both of the previous conditions as being from midnight until the following midnight. Compliance 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. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.2.k.iv This condition addresses specific fuel sulfur requirements for the refinery, allowing the use of diesel-fired emergency equipment as an exception to IX.H.1.g.iv.

Tesoro currently has a number of small diesel-fired emergency engines listed in its AO. No specific provision has ever been made to allow for the use of diesel-fired emergency equipment at the refineries – and while it is clear that the provisions of 2.a.M.A$^{\{OS\}}$ were meant for the burning of liquid fuel in heaters and boilers and not for the application of emergency equipment, such language was not included nor brought forward. This condition (and similar conditions for the other refineries) addresses that oversight.

6.1 Monitoring, Recordkeeping and Reporting

Monitoring for all three conditions is addressed through a variety of methods, depending on the emission point in question. Stack testing, CEMs, parameter monitoring – all are viable options, and have been included in the language of IX.H.2.k.i through IX.H.2.k.iii. As appropriate, these monitoring requirements are complemented by the general provisions of IX.H: 1.e for stack testing, 1.f for CEMs and other continuous monitors, 1.c for recordkeeping and reporting.

Where necessary, additional monitoring, recordkeeping and/or reporting requirements have been directly included in the language of IX.H.2.k to address specific concerns. One example would be the use of leveling gauges on all fuel oil tanks to determine daily fuel oil consumption.

No specific monitoring, recordkeeping or reporting is required for IX.H.2.k.iv, as this condition serves merely as a specific exception to the general refinery requirement prohibiting the burning of liquid fuel oils. Such exception is authorized under the language of IX.H.1.g.iv itself.

Flare gas monitoring requirements – under subsection IX.H.11.g.v.B of the PM2.5 SIP, each refinery, including Tesoro, is required to install and operate a flare gas recovery system or equivalent flare gas minimization process. This system needs to limit hydrocarbon flaring below 14,160 standard cubic meters (m3) (500,000 standard cubic feet (scf)) above the baseline established by the procedure outlined in 40 CFR 60.103a(a)(4). As the specific requirements of IX.H.11.g.v.B were not brought forward into the new maintenance plan, each refinery is required to include monitoring for flare gas such that total flare gas flow rate can be recorded on a daily basis, the daily flare gas recovered for fuel gas processing can be recorded, and an estimate of daily flare gas emissions can be made. All flaring emissions are included in the daily emission Caps, and monitoring of flare gas flows satisfies both the requirements of demonstrating compliance with the daily Caps as well as subsection IX.H.11.g.v.B.

6.2 Discussion of Attainment Demonstration

Generally, the calculation methodology for determination of daily (24-hr) source-wide emissions from the Tesoro refinery is identical to the method used in during the 1991/1992 timeframe of the original SIP. However, several key differences exist:

1. Emissions in the new maintenance plan are lower than in the original SIP

As is shown above in Table 3, the daily SIP Caps have dropped for all pollutants with the exception of PM10. PM10 emissions have increased primarily because of the addition of condensable emissions which were never accounted for in the original SIP. See further discussion in Item 6.2.3 below.

2. All emission units/emission points are included in the new maintenance plan

The original SIP was based on a concept of "SIP Cap sources", where only certain specific sources were included as contributing toward the emission total for a particular pollutant. Other sources, such as the flares, compressors, or SRU incinerator, would be specifically excluded from counting towards this total. This would even be spelled out by a specific requirement in the original SIP. The new maintenance plan eliminates this concept by simply stating that all sources are included, and that the emission "Caps" apply source-wide.

3. Condensable emissions, which were excluded from the original SIP, are included in the new maintenance plan

The original SIP was based on filterable PM_{10} emissions only. The new maintenance plan includes both filterable and condensable PM_{10} emissions. The 24-hour source-wide PM_{10} limit listed in IX.H.2.k.i clearly states that condensable emissions are included from all sources, and the emission factors listed in that condition include values for condensable emissions.

7.0 Interim Emission Limits and Operating Practices

When the new maintenance plan is issued and made effective, the existing SIP Sections IX.H.1-4 will be repealed and replaced. On a federal level, the currently approved 1991 PM10 State Implementation Plan will be superseded with the newest version. As many of the requirements and emission limits in IX.H.1 and IX.H.2 for the refineries have implementation dates of January 1, 2018 or January 1, 2019, an "implementation gap" could have potentially existed between the effective date of the SIP and those future compliance dates.

In order to address this concern, new Subsection IX.H.4, titled Interim Emission Limits and Operating Practices has been established to serve as a bridge between these two periods. For all other point sources listed in IX.H.2 and IX.H.3 the limits apply upon approval by the Utah Air Quality Board of the PM_{10} Maintenance Plan.

There are two main sections of IX.H.4: a set of general requirements that applies to all petroleum refineries in or affecting any PM10 nonattainment/maintenance area, and then a set of specific requirements for each of the four listed refineries in IX.H.2 (BWO, Chevron, Holly and Tesoro). Both the general and specific requirements of IX.H.4 are designed to be used in conjunction with all of the requirements of IX.H.1. As these limits and operating practices are to serve only during the brief period between SIP issuance and January 1, 2019, only a bare minimum of requirements were retained. All requirements are specifically pulled from each source's latest AO, such that the source will continue to remain in compliance; however, each requirement also matches the 2005 State-only SIP. As the control technology for the sources listed in this subsection is installed and operational, the terms and conditions listed in IX.H.1 and IX.H.2 becomes applicable and those limits then replace the limits in this subsection.

For BWO the following conditions and limitations apply during the interim period:

A. Refinery General – retention of the 9.8 kg of SO2 per 1,000 kg of coke burn-off from any

Catalytic Cracking unit limit.

B. Combined emissions of filterable PM10 from gas-fired compressor drivers and all external combustion process equipment, including the FCC/CO Boiler (ESP), shall be no greater than 0.261 tons per day.
C. Combined emissions of SO2 from gas-fired compressor drivers and all external combustion process equipment, including the FCC/CO Boiler (ESP), shall not exceed the following:
    a. November 1 through end of February: 3.699 tons/day;
    b. March 1 through October 31: 4.374 tons/day
D. Combined emissions of NOx from gas-fired compressor drivers and all external combustion process equipment shall be no greater than 1.988 tons per day.

Each limit has an associated compliance demonstration method and averaging period.

8.0 Implementation Schedule

The daily (24-hour) emission Caps are effective as of January 1, 2019. This schedule is dictated by the original RACT requirements established under the $PM_{2.5}$ SIP of 2014 (IX.H.11-13). In order to allow for construction, installation, shakedown and initial testing of the new equipment, this January 1, 2019 date was selected. Demonstration of attainment under the new PM_{10} maintenance plan is also set as January 1, 2019.

The provisions of IX.H.1.a-f (the General Requirements) are effective immediately upon implementation of the new maintenance plan. Those listed in IX.H.1.g (Refineries) have variable implementation dates depending on the specific provision. Some take effect immediately, while others take effect on January 1, 2018 or on January 1, 2019. Again, these dates exactly match those listed in the $PM_{2.5}$ section of the SIP (IX.H.11).

In order to address the possibility of an “implementation gap” from occurring, interim emission limits and operating practices have been established. These interim requirements are found in Subsection IX.H.4 of the new maintenance plan. For complete details on these requirements, please see Item 7.0 above.

9.0 References

Evaluation Report – Tesoro Refinery

UTAH PM_{10} SIP/MAINTENANCE PLAN

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report: University of Utah

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
U of U Campus

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the Utah Maintenance Plan; to address the Salt Lake County PM_{10} Nonattainment Area. This document specifically serves as an evaluation of the University of Utah (U of U) Campus located in Salt Lake County.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

These SIP Subsections were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. Thus, this evaluation report also references an earlier SIP version originally dated June 28, 1991. This SIP was adopted by EPA and published in the federal register on July 8, 1994. This earlier SIP version is often referred to as the "original SIP." In order to distinguish between the various documents in this report, a coding scheme will be used:

- Since Section IX.H of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report.
- When referencing the original SIP (the one issued in 1991/1992 and adopted by EPA in 1995), the qualifier $^{\{OS\}}$ will follow any citation from that document.
- When referencing any new SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: University of Utah – Main Campus
Address: 200 South University Ave Salt Lake City, Utah, Salt Lake County
Owner/Operator: University of Utah
UTM coordinates: 4,512,800 m Northing, 429,440 m Easting, Zone 12

1.2 Facility Process Summary

The University of Utah (U of U) provides the full range of services normally found at a large university. Emissions from U of U are primarily due to the operation of: boilers, comfort heating

equipment, and emergency generators. Two boilers located at the central heating plant are subject to 40 CFR 60 Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generation Units and one is subject to 40 CFR 60 Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. 40 CFR 63, Subpart JJJJJJ, National Emission Standards for Hazardous Air Pollutants for Industrial-Commercial-Institutional Boilers Area Sources applies. Certain emergency power generation engines are subject to 40 CFR 63, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and 40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of the main emitting units from the U of U Campus:

- Building 302, Upper Campus Heating Plant
  Three NSPS boilers (1, 2 and 3). These boilers all have 15% flue gas recirculation, and are fired on natural gas and diesel as a backup fuel. Rating for each boiler is up to 87.5 MMBtu/hr.
- Building 303, Lower Campus Heating Plant
  One pre-NSPS boiler (3) that use natural gas only and at up to 105 MMBtu/hr.
  Four NSPS Boilers (4a, 4b, 5a and 5b) that use natural gas, each rated up to 50 MMBtu/hr.
- Building 303 (Cogeneration Unit).
  One natural gas-fired turbine with duct burner rated at 85 MMBtu/hr. Gas turbine and duct burner are Subject to NSPS, 40 CFR, Part 60, Subpart KKKK.

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at the U of U Campus, rather it is a listing of all significant emission units or emission unit groups.

1.4 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, the U of U Campus baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	13.69
SO_2	0.68
NO_x	63.02

The current PTE values for the U of U, as established by the most recent AO issued to the source (DAQE-AN103540025-13) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	19.29
SO_2	3.85
NO_x	100.05

2.0 Demonstration of Maintaining Attainment

These values have been used in the modeled attainment demonstration. The 2011 actual emissions were used as baseline for model validation. The U of U Campus emissions were projected for future years using growth factors for the manufacturing industry in Salt Lake County. Those emissions projected with growth are intended to represent future actual emissions for the U of U Campus.

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent $PM_{2.5}$ Section of the SIP. This Section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM_{10} SIP sources – including the U of U Campus in specific. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11, IX.H.12 and IX.H.13 – which comprise the $PM_{2.5}$ sections of the SIP, and include this additional RACT application. All requirements from the original PM10 SIP that have not been superseded or replaced, and which are still necessary will also be retained. By necessary, meaning: needed in the demonstration of attainment of the 24-hour standard, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

The U of U is a previously listed SIP source. In the original PM_{10} SIP document for Davis and Salt Lake Counties [IX.H.2 Emission Limitations and Operating Practices (Davis and Salt Lake Counties) – dated 28 June 1991$^{\{OS\}}$, the U of U was listed in Subsection IX.H.2.b.YY$^{\{OS\}}$ as University of Utah – Salt Lake City: (Hot Water Plant). As a listed source there were several requirements and conditions that applied to the facility.

In addition, the U of U is also a listed source in the $PM_{2.5}$ Section of the SIP (see SIP Section IX.H.12.t). As was discussed above in Item 2.0, all limits in this maintenance plan are based on the limits in the $PM_{2.5}$ SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.n.i. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below:

3.1 Original SIP General Requirements

IX.H.2.a General Requirements$^{\{OS\}}$

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a$^{\{OS\}}$ applied to the listed sources found in Utah County, while those found at IX.H.2.a$^{\{OS\}}$ applied to the listed sources found in Salt Lake and Davis Counties. As the then the U of U Campus was located in Salt Lake County, only the general requirements of IX.H.2.a$^{\{OS\}}$ applied. However, except for the additional requirements found under IX.H.2.a.M$^{\{OS\}}$ for petroleum refineries and the specific fuel requirements of IX.H.2.a.N$^{\{OS\}}$, the two subsections are essentially identical.

2.a.A. Stack Testing$^{\{OS\}}$ – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by

SIP subsection IX.H.1.e which incorporates equivalent language.

2.a.B. Visible Emissions{OS} – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which serves the same which incorporates equivalent language.

2.a.C. Visible Emissions (cont.){OS} – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.D. Annual Emission Limitations{OS} – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists.

2.a.E. Recordkeeping Requirements{OS} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders{OS} – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance{OS} – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program.

2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program.

2a.I. Unpaved Operational Areas{OS} – established rules for treating fugitive dust with water sprays or chemical dust suppression.

2.a.J. Actual Emissions{OS} – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsection IX.H of the SIP. This requirement is outdated and obsolete.

2.a.K. Test if Directed{OS} – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions{OS} – established that the definitions contained in R307 apply to Section IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.N. Specific Fuel Requirements for Coal and/or Oil{OS} – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded

by the individual source requirements found in IX.H.2 and IX.H.3 (see specifically the sources Kennecott and BYU). This requirement is now, largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources have the ability to burn any other fuel oils.

3.3 Original SIP Source Specific Requirements

The U of U is in the process of upgrading their Lower Campus Heating Plant with the removal of Units 4 and 5 (each rated at 105 MMBTU/hr) and replacing each of them with two units that are each rated at 50 MMBTU/hr. The new boilers will be ultra-low NO_x and are each rated at 9 ppm NO_x.

Individual source requirements:

2.b.YY.1.{OS} This subsection was a listing of the equipment at the U of U – this subsection has been superseded and is irrelevant. A simple listing of equipment does not constitute an emission limitation, does not impose any restriction on daily emissions, and rapidly becomes out of date as well as impossible to enforce. The original listing found in this subsection will be replaced and would represent a significant step backwards in emission control.

2.b.YY.2.{OS} This subsection set the stack testing limits and the frequencies for the five coal and natural gas combustion units in the Lower Campus High Temperature Heating Plant (Building 303). They were listed as Boiler #1, #2, #3, #4 and #5. The use of coal was discontinued in the 1990's. At the present time all of the units at the U of U burn natural gas as a primary fuel. The units (#1 and #2), each rated at 60 MMBTU/hr, in Building 303 at the Lower Campus High Temperature Heating Plant (LCHTWP) were removed from service in 2007. A cogeneration unit, natural gas fired turbine with waste heat recovery unit (WHRU), was installed to replace the two boilers.

Unit 5 (105 MMBTU/hr and 187 PPM NO_x) in Building 303 has been removed and is being replaced with two ultra-low NO_x boilers (50 MMBTU/hr each and 9 PPM NO_x). Unit 4 will be replaced by 2018 with two ultra-low NO_x boilers (50 MMBTU/hr each and 9 PPM NO_x). Unit 3 will be only used in a stand-by status after Units 4 and 5 have been replaced.

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. The requirements in the subsection are outdated and will be replaced with requirements that will be adjusted to the upgrades. Therefore, this subsection is irrelevant.

2.b.YY.3.{OS} This subsection limited the use of natural gas for firing the boilers from November 1 to February 1. It also limited the coal consumption and the natural gas consumption. These are annual limits and the PM_{10} annual standard has been rescinded. Therefore, this subsection is irrelevant.

2.b.YY.4.{OS} This subsection sets limits on the sulfur content of coal. The U of U no longer burns coal as a fuel. Therefore, this subsection is irrelevant.

2.b.YY.5.{OS} This subsection prohibits flash re-injection. The U of U no longer burns coal as a

fuel. Therefore, this subsection is irrelevant.

2.b.YY.6.{OS} Annual Emissions – established total annual emissions for the U of U Campus. As shown in Table 3 below, the emissions from the U of U plant will be significantly reduced after the boilers are replaced (Units 5 & 6) or upgraded (Unit3 1-34). Therefore, the annual emission estimations have been eliminated. Salt Lake County has not shown an exceedance in over ten years and the reduction in allowable emissions will demonstrate a prevention of backsliding.

Table 3: Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
Current PM_{10}	19.29
Current SO_2	3.852
Current NO_x	100.05
Original SIP PM_{10}	74.3
Original SIP SO_2	219.3
Original SIP NO_x	245.8

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of

either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.$A^{\{OS\}}$ and IX.H.2.a.$A^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.$C^{\{OS\}}$ and IX.H.2.a.$C^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.$B^{\{OS\}}$ and IX.H.2.a.$B^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow – the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been

considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – University of Utah Specific Requirements

The boilers in the 1994 PM_{10} SIP were listed as Boiler No. 1 (60 MMBTU/HR), Boiler No. 2 (60 MMBTU/HR), Boiler No. 3 (105 MMBTU/HR), Boiler No. 4 (105 MMBTU/HR), and Boiler No. 5 (105 MMBTU/HR). Boilers 1 and 2 are located in Building 302 of the Upper Campus High Temperature Heating Plant (UCHTHP). Boilers 3, 4 and 5 are located in Building 303 of the Lower Campus High Temperature Water Plant (LCHTWP).

Currently in the AO (DAQE-AN103540025-13 dated Sept 30, 2013) and Title V (dated May 20, 2015), the boilers are referenced as follows:
Building 302 (UCHP) three boilers rated up to 87.5 MMBTU/hr.
Building 303 (LCHP), two pre-NSPS boilers (3 & 4) each rated up to 105 MMBTU/hr and two NSPS boilers (5 & 6) each rated up to 50 MMBTU/hr.

Boilers 3, 4 and 5 in Building 303, were each originally rated at 105 MMBTU/hr. The U of U has replaced Boiler No. 5 with two 50 MMBTU/hr boilers (5a & 5b), and has removed Boiler No.4. Boiler No. 4 will be replaced with two boilers that are each rated at 50 MMBTU/hr. During the $PM_{2.5}$ SIP process, to avoid confusion on the replacement of the boilers (3, 4 and 5), it was decided that the boilers replacing 4 would be renamed 4a and 4b and the boilers replacing 5 would be named 5a and 5b. If Boiler No. 3 is replaced the replacement boilers will be named 3a and 3b.

IX.H.2.l.i This sets NO_x limits for Units 3, 4a, 4b, 5a and 5b. These limits will result in a significant reduction from the original SIP limits. Condition H.1.d of the general conditions requires the limits to apply at all times.

During the development of the $PM_{2.5}$ SIP, it was determined that the emissions from the boilers in Building 302 (Units #1, #2 and #3) did not warrant a RACT analysis. They were already equipped with low NO_x burners and flue gas recirculation and each had an actual NO_x emission rate in the 2008 emissions inventory of 4.2 tpy. In order to meet the $PM_{2.5}$ SIP RACT, the U of U upgraded the boilers with an O_2 trim system to reduce NO_x emissions. It was not economically feasible to require an SCR or SNCR for these boilers. Their low NO_x emission rate coupled with the reduction in NO_x emissions from the installation of the O_2 trim systems, did not warrant a stack testing requirement.

IX.H.2.l.ii This condition establishes stack test frequencies for the Units 3-5 and the turbine at every three years. Condition H.1.e.H of the general conditions requires testing to be conducted at 90% of the production rate achieved in the previous three (3) years.

The 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.

IX.H.2.l.iii This condition requires that Unit 3 be used only as a back-up/peaking boiler. It

may only be operated for 300 hours per year. If it is operated longer than 300 hours, then it will be required to be upgraded to low NO_x burners.

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.

5.1 Monitoring, Recordkeeping and Reporting

Monitoring for all three emission points is addressed through stack testing. As appropriate, these monitoring requirements are complemented by the general provisions of IX.H.: 1.e for stack testing, and 1.c for recordkeeping and reporting.

5.2 Discussion of Attainment Demonstration

Generally, the calculation methodology for determination of emissions from the U of U Campuse is identical to the method used in during the 1991/1992 timeframe of the original SIP. However, several key differences exist:

1. Emissions in the new maintenance plan are lower or equal to the original SIP

As is shown above in the tables above, the emissions PM_{10}, SO2 and NO_x emissions from the U of U Campus have dropped significantly.

2. Condensable emissions, which were excluded from the original SIP, are included in the new maintenance plan

The original SIP was based on filterable PM_{10} emissions only. The new maintenance plan includes both filterable and condensable PM_{10} emissions.

6.0 Implementation Schedule

All RACT imposed limits are in place. After January 2019, boiler #3 can only be operated as a back-up boiler, unless it has been retrofit with controls that provide for RACT compliance.

7.0 References

- U of U Campus, $PM_{2.5}$ SIP Major Point Source RACT Documentation
- UDSHW Contract No. 12601, Work Assignment No. 7, Utah $PM_{2.5}$ SIP RACT Support – TechLaw Inc.
- U of U AO DAQE-AN103540025-13
- U of U Campus Title V 3500063003

UTAH PM_{10} SIP/MAINTENANCE PLAN

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report:
West Valley Power Holdings, LLC. - West Valley Power Plant

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM10 SIP/MAINTENANCE PLAN EVALUATION REPORT
West Valley Power Holdings, LLC. - West Valley Power Plant

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the Utah Implementation Plan (SIP); to address the Salt Lake County PM_{10} Nonattainment Area (SLCNA). This document specifically serves as an evaluation of the West Valley Power Holdings operated West Valley Power Plant.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Sections IX.H.1-4 of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report.
- When referencing the original SIP with an effective date of August 8, 1994 the qualifier $^{\{OS\}}$ will follow any citation from that document.
- In reference to the updated Utah County SIP with an effective date of January 22, 2003 the qualifier $^{\{UC\}}$ will follow any citation from that document.
- When referencing any new Maintenance Plan/SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: West Valley Power Plant
Address: 5935 West 4700 South, West Valley City, Utah, Salt Lake County
Owner/Operator: West Valley Power Holdings, LLC.
UTM coordinates: 4,502,036 Northing, 412,828 Easting, Zone 12

1.2 Facility Process Summary

The West Valley Power Plant (WVPP) is a natural gas-fired electric generating plant consisting of five (5) simple cycle turbines. Each turbine has a power output rating of 43.4 MW. The plant is located in Salt Lake County, which is part of the Salt Lake City $PM_{2.5}$ nonattainment area.

The turbines are fired on pipeline quality natural gas, have water injection and evaporative mist inlet air cooling. The plant is a Phase II acid rain source and a major source for both NOx and CO emissions. The plant was permitted in 2002 as a PSD major source and a PM_{10} nonattainment area major source for NOx emissions, and ozone maintenance area major source (again for NOx emissions). Therefore, analysis of LAER was required for PM_{10}, NOx, SO_2 and VOC emissions; analysis of BACT was required for all other emissions.

1.3 Facility Criteria Air Pollutant Emissions Sources

The source consists of five (5) GE LM6000PC Sprint simple cycle natural gas-fired combustion turbines. Emissions are presently controlled using a combination of exclusive firing of pipeline quality natural gas, selective catalytic reduction (SCR), oxidation catalysts and water injection.

1.4 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, WVPP's baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	6.57
SO_2	0.5
NO_x	20.37

The current PTE values for WVPP, as established by the most recent AO issued to the source (DAQE-282-02) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	233.65
SO_2	12.1
NO_x	162.06

However, please see Section 2.0 (and Table 3) for further details on WVPP's true PTE value.

2.0 Modeled Emission Values

Unlike the base year inventory, which used only the 2011 actual emissions for each source to set the baseline for modeling, a modified version of the PTE values was used for the modeled attainment demonstration. Beginning with the PTE values listed in Table 2 (from the most recent

approval order issued to WVPP in 2002), these emissions were then "trued-up" by including the expected effects from implementation of RACT from the $PM_{2.5}$ SIP. This true-up yields a 2019 Projected Emission Value for each of the pollutants of concern. Where necessary, these values were further corrected for condensable particulates using simple correction factors based on fuel consumed or process type.

Where gaseous fuels such as natural gas were combusted, filterable-only emissions were converted to a filterable+condensable emission value by multiplying the filterable rate by 4. For natural gas, AP-42 lists the various emission factors as:

Filterable PM: 1.9 lb/106 scf
Condensable PM: 5.7 lb/106 scf
Total PM: 7.6 lb/106 scf

In other words, the total PM is almost exactly four times the filterable emission value. Unfortunately, this adjustment had already been made at the WVPP when the plant was originally permitted. A comparison of the actual emissions table (Table 1), specifically the two values of PM10 and NOx, to the same two values in Table 2 – shows a vastly different ratio. In reviewing the original engineering notes for the 2002 AO, the intent was to include condensable emissions for PM10, but it appears that the calculation was performed twice, in effect multiplying the filterable rate by 16, rather than by 4. When comparing the emission values with similarly designed and controlled equipment, such as that installed at the PacifiCorp Gadsby plant, the assumption that the calculation was performed twice becomes even more apparent. After correcting the PM10 value for this error, a far more reasonable value of 58.41 tpy is obtained. Comparing Table 1 and Table 2, ratios of 0.323 and 0.361 are obtained – the remaining difference resulting from startup and shutdown periods versus normal operation, and the inherent variability of actual emissions versus potential maximums.

For WVPP, the true-up and correction results in the following modeled emission values – summarized in Table 3.

Table 3: Modeled Emission Values

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	58.41
SO_2	12.1
NO_x	162.06

The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11-13 – which comprise the PM2.5 sections of the SIP. All requirements from the original PM10 SIP that have not been superseded or replaced, and which are still necessary, will also be retained. By necessary, meaning: significant from the standpoint of PM10 control, or in demonstrating that no backsliding in the application of RACT as viewed from the original SIP has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

WVPP was never previously listed in the PM10 SIP. The plant was issued its permit authorizing construction in 2002, nearly ten years after the original SIP issuance and approval dates. Its construction was only made possible through the use of emission offset credits held by the owner/operator at the time, PacifiCorp Power Marketing (pedigree of emission offset credits

available upon request).

However, WVPP is a listed source in the PM2.5 Section of the SIP (see SIP Section IX.H.12.d as CER Generation II, LLC). As was discussed above in Item 2.0, all limits in this maintenance plan are based on the limits in the PM2.5 SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.d. Therefore, a comparison only of the original SIP general requirements can be found below. No direct comparison can be made of the source specific requirements.

3.1 Original SIP General Requirements

IX.H.2.a General Requirements{OS}

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a{OS} applied to the listed sources found in Utah County, while those found at IX.H.2.a{OS} applied to the listed sources found in Salt Lake and Davis County. As the WVPP power plant is located in Salt Lake County, only the general requirements of IX.H.2.a{OS} would have applied.

2.a.A. Stack Testing{OS} – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which incorporates equivalent language.

2.a.B. Visible Emissions{OS} – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.C. Visible Emissions (cont.){OS} – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

2.a.D. Annual Emission Limitations{OS} – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists, and no source-specific annual SIP Caps appear in either IX.H.2 or IX.H.3 of the new maintenance plan.

2.a.E. Recordkeeping Requirements{OS} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

2.a.F. Approval Orders{OS} – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.G. Proper Maintenance{OS} – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program under R307-401-4(1).

2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities

were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program under R307-401-3(1)(b).

2a.I. Unpaved Operational Areas{OS} – established rules for treating fugitive dust with water sprays or chemical dust suppression. This requirement has been superseded by the most recently EPA approved nonattainment area fugitive dust rules.

2.a.J. Actual Emissions{OS} – established that the actual emissions included for each listed source in subsection IX.H.2.b would not be used for compliance purposes. This subsection is no longer needed as a listing of individual source actual emissions are no longer included in the requirements of subsection IX.H of the SIP. This requirement is outdated and obsolete.

2.a.K. Test if Directed{OS} – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

2.a.L. Definitions{OS} – established that the definitions contained in R307 apply to Section IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

2.a.M. Petroleum Refineries{OS} – This is a fairly lengthy subsection pertaining only to the petroleum refineries. This subsection has its own sub-subsections, owing to the overall length and complexity. This subsection has been replaced generally by the new maintenance plan requirements found at IX.H.1.g; however, as this source is not a petroleum refinery, this subsection does not apply.

2.a.N. Specific Fuel Requirements for Coal and/or Oil{OS} – established that specific rules for the sulfur content of these fuels also existed and applied. This subsection has since been superseded by the individual source requirements found in IX.H.2 and IX.H.3 (see specifically the sources Kennecott and BYU). This requirement is now largely irrelevant as few sources have the ability or authority to burn coal, and the rules on the sulfur content of fuel oil have been updated with lower sulfur requirements – specifically the requirements on the sulfur content allowed in diesel fuel found under 40 CFR 80.510(c) for off-highway diesel and 40 CFR 80.520(a) for on-highway diesel. None of the listed sources have the ability to burn any other fuel oils.

4.0 Discussion of Daily Emission Values

Table 4 is a comparison of annual PTE values with an expected daily (24-hour) emission value based on the short term limits found in IX.H. This is one of the few cases where re-examination of the original assumptions yielded an error in calculations. In this case, the PM10 values for the WVPP were miscalculated, and the condensable adjustment had been applied twice. When this error was corrected, a much more reasonable PM10 value was obtained, as shown in Table 4 below.

Table 4: Comparison Table – New Maintenance Plan Emissions

All values in tons	SO_2	NO_x	PM_{10}
Annual	12.1	162.06	58.41[&]
Daily (24-hr)	-	0.6	-

[&] includes condensable emissions

There is no short term limit established for SO2 emissions given the low sulfur content of natural gas. There is also no specific limitation established for direct PM10 emissions. When the permit was originally issued, total PM10 emissions were estimated as only 58 tons per year (see the discussion in Section 2.0 above) – not enough to warrant a turbine-by-turbine limitation. Especially given that no additional controls were identified through the LAER analysis to further reduce direct PM10 emissions beyond the passive use of good combustion controls and natural gas as fuel.

The daily value listed for NOx includes an allowance for startup and shutdown emissions. As a 24-hour estimate, this NOx value is inherently higher than simply dividing the annual emission value by 365 days. Also, this NOx estimation is for comparison purposes only, and is not to be viewed as a SIP limitation. Those limits are found specifically in Section IX.H.2.m of the SIP.

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference. As specifically stated in subsection IX.H.1.a below, these general requirements apply to all sources subsequently listed in either IX.H.2 (Salt Lake County) or IX.H.3 (Utah County), and are in addition to (and in most cases supplemental to) any source-specific requirements found within those two subsections.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation. All conditions in these subsections are strictly in accordance with EPA approved methods and guidelines.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow – either in the Petroleum Refinery provisions of IX.H.1.g, or the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement

has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – WVPP Specific Requirements

The WVPP specific conditions in Section IX.H.2 address those limitations and requirements that apply only to the WVPP Power Plant in particular.

IX.H.2.m.i Emissions of NOx from each individual turbine shall be no greater than 5 ppmdv (15% O2, dry) based on a 30-day rolling average.

IX.H.2.m.ii Total emissions of NOx from all five turbines shall be no greater than 37 lbs/hour (15% O2, dry) based on a 30-day rolling average.

A 24-hour NOx emission limitation shall be established following completion of the public comment period. Once established, this new 24-hour limitation will replace the value listed in IX.H.2.m.ii, although the intention is that the two values should be functionally equivalent in terms of overall modeled emissions.

IX.H.2.m.iii The NOx emission rate (lb/hr) shall be calculated by multiplying the NOx 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.

Similarly, as with IX.H.2.m.ii above, once the comment period has passed and a new 24-hour emission limitation has been established, an equivalent compliance methodology will be included. This methodology shall continue to make use of CEM data, but no running total shall need to be maintained towards a rolling average.

IX.H.2.m.iv Combustion Turbine Startup / Shutdown Emission Minimization Plan

Subparagraph A: Startup begins when natural gas is supplied to the combustion turbine(s) with the intent of combusting the fuel to generate electricity. Startup conditions end within sixty (60) minutes of natural gas being supplied to the turbine(s).

Subparagraph B: Shutdown begins with the initiation of the stop sequence of a turbine until the cessation of natural gas flow to the turbine.

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

5.1 Monitoring, Recordkeeping and Reporting

Monitoring for IX.H.2.m.i is specifically outlined in IX.H.2.m.ii. All NOx monitoring is covered by CEM. CEM monitoring requirements are found in IX.H.1.f. Recordkeeping is subject to the requirements of IX.H.1.c.

5.2 Discussion of Attainment Demonstration

WVPP is primarily a source of NOx emissions. While some direct PM10 and SO2 emissions added to the overall contribution from WVPP, it is a listed source because of NOx. Although not listed in the original PM10 SIP, the WVPP remains viable within the maintenance plan through R307-403-5 – Offsets: PM10 Nonattainment Areas. When the WVPP was originally authorized for construction, the owner/operator PacifiCorp Energy was required to produce and use emission offset credits as outlined under R307-403-5(1)(b). As the total emissions of the plant was larger than the 50 ton per year threshold listed in that rule, the offset credits required needed to be obtained at a ratio of 1.2:1. These offset credits also satisfied the emission offsetting requirement of 40 CFR 51.165(a)(9)(i). Thus, the apparent increase in emissions to the Salt Lake County airshed was already accounted for as available growth under the offsetting program. No backsliding has taken place, and continued attainment of the PM10 standard can be demonstrated.

6.0 Implementation Schedule

The requirements imposed on the WVPP are effective immediately. While some provision was made for sources generally to implement the RACT requirements of the PM2.5 SIP (and which were included as part of the modeled emission values for each source as discussed in that section above), the WVPP did not have any required RACT modifications to undertake. The emission limits listed in IX.H.2.m can be applied immediately. Similarly, the provisions of IX.H.1.a-f (the General Requirements) can also be applied immediately.

7.0 References

Evaluation Report – WVPP

UTAH PM_{10} SIP/MAINTENANCE PLAN

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report:
Brigham Young University – Main Campus

Utah Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
Brigham Young University – Main Campus

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.3 of the Utah Implementation Plan; to address the Utah County PM_{10} Nonattainment Area. This document specifically serves as an evaluation of Brigham Young University's Main Campus.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Section IX.H of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report.
- When referencing the original SIP (the one issued in 1991/1992 and adopted by EPA in 1995), the qualifier $^{\{OS\}}$ will follow any citation from that document.
- In reference to the updated Utah County SIP with an effective date of January 22, 2003 the qualifier $^{\{UC\}}$ will follow any citation from that document.
- When referencing any new SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Brigham Young University – Main Campus
Address: Main Campus, Brigham Young University, Provo, Utah, Utah County
Owner/Operator: Brigham Young University
UTM coordinates: 4,455,200 km Northing, 445,000 km Easting, Zone 12

1.2 Facility Process Summary

Brigham Young University (BYU) provides the full range of services normally found at a large university. Emissions from BYU are primarily due to the operation of: boilers, comfort heating equipment, and emergency generators. Two boilers located at the central heating plant are subject to 40 CFR 60 Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generation Units and one is subject to 40 CFR 60 Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. 40 CFR 63, Subpart JJJJJJ, National Emission Standards for Hazardous Air Pollutants for Industrial-Commercial-Institutional Boilers Area Sources applies. Certain emergency power generation engines are subject to 40 CFR 63, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and 40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of installations at the BYU campus:

- Liquid petroleum-fired emergency generator
- Central Heating Plant Boilers
  Unit #1 (natural gas-fired)
  Unit #2 (coal-fired)
  Unit #3 (coal-fired)
  Unit #4 (natural gas-fired)
  Unit #5 (coal-fired)
  Unit #6 (natural gas-fired)
- Central Heating Plant Baghouse
- Boilers less than 5.0 MMbtu/hr (natural gas-fired)
- Emergency Generators

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at BYU, rather it is a listing of all significant emission units.

1.4 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, the BYU Campus baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	11.40
SO_2	99.22
NO_x	131.71

The current PTE values, as established by the most recent AO issued to the source (DAQE-AN107900015-13), are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	13.06

SO_2	215.12
NO_x	113.72

2.0 Demonstration of Maintaining Attainment

Unlike the base year inventory, which used only the 2011 actual emissions for each source to set the baseline for modeling, a modified version of the PTE values was used for the modeled attainment demonstration. Beginning with the PTE values listed in Table 2 (from the most recent approval order issued to BYU in 2013), these emissions were then "trued-up" by including the expected effects from implementation of RACT from the $PM_{2.5}$ SIP. This true-up yields a 2019 Projected Emission Value for each of the pollutants of concern. Where necessary, these values were further corrected for condensable particulates using simple correction factors based on fuel consumed or process type.

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent $PM_{2.5}$ Section of the SIP. This Section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM_{10} SIP sources. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11, IX.H.12 and IX.H.13 – which comprise the $PM_{2.5}$ sections of the SIP, and include this additional RACT application. All requirements from the original PM_{10} SIP that have not been superseded or replaced, and which are still necessary will also be retained. By necessary, meaning: needed in the demonstration of attainment of the 24-hour standard, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

BYU is a previously listed SIP source. In the original PM_{10} SIP document for Utah County [IX.H.1 Emission Limitations and Operating Practices (Utah County) – dated 24 September 1990 and Updated June 28, 1991]$^{\{OS\}}$, BYU was listed in Subsection IX.H.1.b.B$^{\{OS\}}$ as Brigham Young University (Heating Plant). As a listed source there were several requirements and conditions that applied to the facility.

The original PM_{10} SIP for Utah County was superseded in 2002, and was made effective by EPA on January 22, 2003. BYU was not a listed source in the EPA approved Utah County PM_{10} SIP. Therefore, a comparison was not made of the approved PM_{10} SIP and the new maintenance plan.

3.1 Original SIP General Requirements

IX.H.1.a General Requirements$^{\{UC\}}$

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a$^{\{OS\}}$ applied to the listed sources found in Utah County, while those found at IX.H.2.a$^{\{OS\}}$ applied to the listed sources found in Salt Lake and Davis County. Those original requirements were then fully superseded with the Utah County updated SIP$^{\{UC\}}$ issued in 2002 and made effective by EPA in January 2003. The comparison shown here is between the new maintenance plan and that most recent EPA-approved version.

1.a.A. Stack Testing{UC} – this subsection covered the general methods and procedures for conducting stack testing. As with the original SIP, it included the establishment of a pretest conference, and the use of specific EPA test methods. However, it lacked the establishment of a pretest protocol. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which incorporates equivalent language.

1.a.B. Annual Emission Limitations{UC} – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists, and no source-specific annual SIP Caps appear in either IX.H.2 or IX.H.3 of the new maintenance plan.

1.a.C. Recordkeeping Requirements{UC} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

1.a.D. Proper Maintenance{UC} – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program, under R307-401-4(1).

1.a.E. Definitions{UC} – established that the definitions contained in R307 apply to Section IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

1.a.F. Visible Emissions{UC} – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

1.a.G. Visible Emissions (cont.){UC} – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

1.a.H. Unpaved Operational Areas{UC} – established rules for treating fugitive dust with water sprays or chemical dust suppression. This requirement has been superseded by the nonattainment area fugitive dust rules of R307-309.

There were several additional subsections found in the original SIP for Utah County which did not appear in the Utah County updated SIP{UC}. These conditions were primarily outdated and no longer applicable. For the sake of completeness, they are included below.

1.a.F. Approval Orders{OS} – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program, under R307-401-3(1)(b).

2.a.K. Test if Directed{OS} – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any

additional testing to demonstrate compliance status as deemed necessary by the Director.

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions. This recordkeeping requirement includes records of startup/shutdown implementation procedures, as well as CEMS testing data and stack testing data, as applicable.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of

the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – Brigham Young University Specific Requirements

The BYU specific conditions in Section IX.H.3 address those limitations and requirements that apply only to the BYU Campus in particular.

IX.H.3.a.i This condition requires that all of the central heating plant boilers to operate on natural gas during the winter season from November 1 to February 28. It limits sulfur content of the backup fuel, fuel oil.

IX.H.3.a.ii This condition sets the NO_x emission rates for Units #1 thru #6.

BYU will be required to upgrade units #4 and #6 by January 1, 2017. The upgraded boilers will be tested by March 1 of that year.

Units #2, #3 and /#5 operate on coal. Therefore, they cannot operate during the winter months.

The NO_x lb/hr emission rate is calculated with the following equation:

ER = (ppm conc/1,000,000) * Mol wt of gas (g) * (1/453.59) * (DSCFM/0.848930) * 60
or
ER = ppmdv * (1.194×10^{-7}) * (Q_s flow rate in dscf/min*60)

The ppm for the last stack test in August 2014 for Unit #4 was 74 with a flow rate of 37,500 dscfm. This calculated to a mass emission rate of 15.1 lb/hr. Unit #6 was 81 ppm with a flow rate of 34,800 dscfm. This calculated to a mass emission rate of 18.6 lb/hr. The flow rates were determined by 40 CFR Part 60 Appendix A Method 2 and the concentrations were determined by 40 CFR Part 60Appendix A Method 7e.

The ppm for the last stack test in August 2014 for Unit #2 was 207 with a flow rate of 18,522 dscfm. This calculated to a mass emission rate of 11.4 lb/hr. Unit #3 was 218 ppm with a flow rate of 30,338 dscfm. This calculated to a mass emission rate of 21.9 lb/hr. Unit #5 was 242 ppm with a flow rate of 27,156 dscfm. This calculated to a mass emission rate of 25.6 lb/hr.

IX.H.3.a.iii This condition sets the stack testing frequency and when the initial test is required. It allows Unit #1 to be operated as a back-up boiler.

BYU is upgrading Units #4 and #6 to a NO_x rating of 36 ppm by January 1, 2017. This is why they are required to perform a stack test by March 1, 2017. These items represent large capital investments with significant lead times, engineering, construction, startup, shakedown and testing involved. These dates were reached through negotiation with the source based on the source's expected construction schedule after consideration of each factor.

IX.H.3.b.iv This condition limits the emissions from the central heating plant. The first requirement limits the amount of hours used during start-up and shutdown. This limit gives BYU time to ramp up the boilers in the winter months when classes are being held and shut them down when the weather permits.

The second requirement is for limiting SO_2 emissions by limiting the coal sulfur content. This condition also sets the requirements for how the sulfur content is tested.

5.1 Monitoring, Recordkeeping and Reporting

Monitoring, recordkeeping and reporting for the conditions above is addressed through the general requirements in Subsection IX.1.c.

5.2 Discussion of Attainment Demonstration

Generally, the calculation methodology for determination of emissions for the BYU Campus is similar to the method used in during the 1991/1992 timeframe of the original SIP and the Utah

County SIP.

6.0 Implementation Schedule

The requirements imposed on BYU are effective immediately. BYU is scheduled to replace Unit #4 and Unit #6 burner spud tips with low NOx tips and add a minimum of 18% Flue Gas Recirculation by January 1,2017. The general requirements, IX.H.1.a-f, can also be applied immediately.

7.0 References

- BYU, $PM_{2.5}$ SIP Major Point Source RACT Documentation
- UDSHW Contract No. 12601, Work Assignment No. 7, Utah $PM_{2.5}$ SIP RACT Support – TechLaw Inc.
- BYU Approval Order DAQE-AN107900015-13
- BYU Title V Operating Permit 4900004002
- BYU stack test results for 2014 and 2011.

Evaluation Report – BYU Campus

UTAH PM_{10} SIP/MAINTENANCE PLAN

Utah County Nonattainment Area

Supporting Information

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PM_{10} SIP/Maintenance Plan Evaluation Report: Geneva Nitrogen, LLC.

Salt Lake County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
Geneva Nitrogen

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.3 of the Utah Maintenance Plan; to address the Utah County PM_{10} Nonattainment Area. This document specifically serves as an evaluation of the Geneva Nitrogen plant.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law.

In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Section IX.H of the 2005 State-only SIP will be repealed entirely and will not be referred to in this report.
- When referencing the original SIP with an effective date of August 8, 1994 the qualifier {OS} will follow any citation from that document.
- In reference to the updated Utah County SIP with an effective date of January 22, 2003 the qualifier {UC] will follow any citation from that document.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Geneva Nitrogen
Address: 1165 North 1600 West, Vineyard, Utah, Utah County
Owner/Operator: Geneva Nitrogen, LLC
UTM coordinates: 4,463,352 m Northing, 437,470 m Easting, Zone 12

1.2 Facility Process Summary

Geneva Nitrogen is a Nitrogen Plant that produces industrial products. There are three

manufacturing processes located on site. The processes are the nitric acid manufacturing, ammonium nitrate solution manufacturing, and solid ammonium nitrate manufacturing. The main emission units are two nitric acid plants, one prill tower, two prill dryer vents, and one prill cooler vent.

1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of the main emitting units from the Geneva Nitrogen plant:

- Montecatini Acid Plant with low temperature selective catalytic reduction unit
- Weatherly Acid Plant with low temperature selective catalytic reduction unit
- Prill Predryer with cyclone scrubber system
- Prill Dryer with cyclone scrubber system
- Prill Cooler with cyclone scrubber system
- Prill Tower
- Natural gas boiler (25.0 MM Btu/hr) with low NOx burner

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at the facility, rather it is a listing of all significant emission units.

1.4 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, Geneva Nitrogen's baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	32.23
SO_2	0.001
NO_x	105.89

The current PTE values for Geneva Nitrogen, as established by the most recent AO issued to the source (DAQE-AN0825005-03) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	111.17
SO_2	0.03
NO_x	227.53

2.0 Demonstration of Maintaining Attainment

These values have been used in the modeled attainment demonstration. The 2011 actual emissions were used in some fashion. The refineries and differed from most of the listed sources in the establishment of projection year inventories. Rather than using a combination of "trued-up" 2019 actual emissions plus projection year growth values, DAQ instead simply applied the refineries' individual source-wide emission "Caps" as the 2019 true-up value, and then assigned a growth factor of zero (0) to each of the projection years. In this way, DAQ ensured that the maximum potential emissions from each refinery are what was used for each modeled projection

year. As these Caps are directly established for each listed refinery and are found in the limits of Section IX.H of the SIP, this ensures that the potential emissions will never increase.

Although a specific application of new RACT is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent PM2.5 Section of the SIP. This Section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM10 SIP sources. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11, IX.H.12 and IX.H.13 – which comprise the PM2.5 sections of the SIP, and include this additional RACT application. All requirements from the original PM10 SIP that have not been superseded or replaced, and which are still necessary will also be retained. By necessary, meaning: needed in the demonstration of attainment of the 24-hour standard, or in demonstrating that no backsliding in the application of RACT has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

Geneva Nitrogen is a previously listed SIP source. In the original PM_{10} SIP document for Utah County [IX.H.1 Emission Limitations and Operating Practices (Utah County) – dated 24 September 1990 and Updated June 28, 1991]$^{\{OS\}}$, Geneva Nitrogen was listed in Subsection IX.H.1.b.H$^{\{OS\}}$ as La Roche Industries, Inc. As a listed source there were several requirements and conditions that applied to the facility.

The original PM_{10} SIP for Utah County was superseded in 2002. In the 2002 PM10 SIP document for Utah County [IX.H.1 Emission Limitations and Operating Practices (Utah County) – dated 24 September 1990 and Updated June 28, 1991]; February 27, 1997, and April 24, 2002]$^{\{UC\}}$, Geneva Nitrogen was listed in Subsection IX.H.1.b.A as Geneva Nitrogen, Inc.

In addition, Geneva Nitrogen is also a listed source in the $PM_{2.5}$ Section of the SIP (see SIP Section IX.H.13.b). As was discussed above in Item 2.0, all limits in this maintenance plan are based on the limits in the $PM_{2.5}$ SIP; either in the general requirements of subsection IX.H.13 or the source specific requirements of IX.H.13.b. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below:

3.1 Original SIP General Requirements

IX.H.2.a General Requirements$^{\{OS\}}$

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a$^{\{OS\}}$ applied to the listed sources found in Utah County, while those found at IX.H.2.a$^{\{OS\}}$ applied to the listed sources found in Salt Lake and Davis County. As the then La Roche nitrogen plant was located in Utah County, only the general requirements of IX.H.1.a$^{\{OS\}}$ applied.

1.a.A. Stack Testing$^{\{UC\}}$ – this subsection covered the general methods and procedures for conducting stack testing, including the establishment of a pretest protocol, pretest conference, and the use of specific EPA test methods. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which incorporates equivalent language.

1.a.B. Annual Emission Limitations$^{\{UC\}}$ – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the

first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists, and no source-specific annual SIP Caps appear in either IX.H.2 or IX.H.3.

1.a.C. Recordkeeping Requirements{UC} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

1.a.D. Proper Maintenance{UC} – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program.

1.a.E. Definitions{UC} – established that the definitions contained in R307 apply to Section IX.H. This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

1.a.F. Visible Emissions{UC} – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

1.a.G. Visible Emissions (cont.){UC} – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

1.a.H. Unpaved Operational Areas{UC} – established rules for treating fugitive dust with water sprays or chemical dust suppression.

3.2 Utah County SIP Source Specific Requirements

Individual source requirements:

1.b.A.1.{UC} Stack Testing Limits - A) established the NO_x daily and annual emission limits for the Montecatini Acid Plant Vent. B) established the NO_x daily and annual emission limits for the Weatherly Acid Plant Vent. C) established the PM_{10} daily and annual emission limits for the Prill Tower. This subsection shows how compliance would be demonstrated by multiplying the most recent stack test results by the appropriate hours of operation for the daily and annual limits.

1.b.A.2.{UC} Stack Testing to Show Compliance – This subsection sets the frequency of compliance testing for the limits set in the subsection referenced in 1.b.A.1 above.

The new PM_{10} emission limits are lower than the original limits, on both annual and 24-hour basis (see the comparison table below).

The new PM_{10} and NO_x emission limits are lower than the original limits.
Caps, on both an annual and 24-hour basis (see the comparison table below).

As before, the compliance methodology included in SIP subsection IX.H.2.g.i uses the amount of fuel burned multiplied by the emission factor for each fuel type. Monitoring, recordkeeping and reporting requirements have also been included (for more details, see the discussion of the Section IX, Part H limits outlined in Item 4.1 below).

Table 3: Comparison Table – Old SIP Caps vs New SIP Caps

	Montecatini*		Weatherly*		Prill**	
	NO_x Original	NO_x New	NO_x Original	NO_x New	PM_{10} Original	PM_{10} New
Annual	140		83.8		86[$]	79[$]
Daily (24-hr)	0.389	0.370	0.233	0.220	0.24[$]	0.22[$]
Hourly		30.8		18.4		

* These emission points do not have a new annual limit or a daily limit. To show a comparison the daily limit is actually 24 times the hourly limit.
** There is no annual limit in the new PM_{10} SIP. These limits show a comparison between the 1994 and the 2002 SIPs.
[$] filterable emissions only
[&] includes condensable emissions

4.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions. This recordkeeping requirement includes records of startup/shutdown implementation procedures, as well as CEMS testing data and stack testing data, as applicable.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

4.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow – the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

4.2 Discussion of Attainment Demonstration

As is discussed above in Items 4.0 and 4.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement has been removed, careful consideration was given as to its specific need, and whether its

retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

5.0 New Maintenance Plan – Geneva Nitrogen Specific Requirements

The Geneva Nitrogen specific conditions in Section IX.H.3.b address those limitations and requirements that apply only to the Geneva Nitrogen plant in particular.

IX.H.3.b.i This condition establishes PM_{10} and $PM_{2.5}$ emission limits for the Prill Tower on a ton per day basis. Emissions are calculated on a filterable plus condensable basis. The filterable plus condensable limits are 0.236 tons PM_{10} per day and 0.196 tons $PM_{2.5}$ per day.

The condition also includes the definition of a day as being from midnight until the following midnight. Compliance shall be determined daily by applying the emission factors determined from the most current performance test to the hours of operation per day.

IX.H.3.b.ii This condition sets the stack testing frequency and the method for calculating compliance with the limit. The limit shall be verified by stack testing every three years.

Geneva stack tested the PM_{10} in 2011 and 2014. The total PM (filterable + condensable) was tested during these two test dates. The next stack test will be conducted in 2017.

IX.H.3.b.iii This condition establishes NO_x emission limit for the Montecatini Plant on a lb per hour basis. The limit is 30.8 lb/hr.

IX.H.3.b.iv This condition establishes NO_x emission limit for the Weatherly Plant on a lb per hour basis. The limit is are 18.4 lb/hr and 350 ppmdv.

IX.H.3.b.v This condition addresses testing for the Montecatini Plant and the Weatherly Plant.

Stack testing will be conducted every three years for the Montecatini Plant and every three years for the Weatherly Plant. The Montecatini was tested at two years{OS} but has been moved to three years. This enables Geneva Nitrogen to perform a cycle that allows them to conduct a stack test every year. The stack test for the Montecatini Plant was conducted on May 11, 2015, and the Weatherly Plant was tested on May 12, 2015. The next scheduled test will be in 2017 for the Montecatini Plant and in 2018 for the Weatherly Plant.

IX.H.3.b.vi This condition addresses start-up and shutdown of the abatement systems for the acid plants. During periods of start-up or shut-down the SCR's do not maintain normal operating temperature which may result in temporarily elevated levels of NO_x being emitted . During the shut-down or start-up process it may take up to 2 hours to reach the desired temperature to get the NO_x abatement within the normal permitted limits to control the NO_x emissions from the Montecatini or Weatherly Acid Plants.

5.1 Monitoring, Recordkeeping and Reporting

Monitoring for all three conditions is addressed through a variety of methods, depending on the

emission point in question. Stack testing is a viable option, and has been included in the language of IX.H.3.b.i, IX.H.3.b.iii and IX.H.3.b.iv. As appropriate, these monitoring requirements are complemented by the general provisions of IX.H: 1.e for stack testing, and 1.c for recordkeeping and reporting.

5.2 Discussion of Attainment Demonstration

Generally, the calculation methodology for determination of daily (24-hr) source-wide emissions from the Geneva Nitrogen plant is identical to the method used in during the 1991/1992 timeframe of the original SIP and the 2002 SIP. However, several key differences exist:

1. Emissions in the new maintenance plan are lower than in the original SIP

As is shown above in Table 3, the daily SIP limits have dropped for all pollutants of concern [PM_{10} and NO_x]. The annual emissions have also dropped for all pollutants, although no annual Cap is required.

2. Condensable emissions, which were excluded from the original SIP, are included in the new maintenance plan

The original SIP was based on filterable PM_{10} emissions only. The new maintenance plan includes both filterable and condensable PM_{10} emissions. The 24-hour source-wide PM_{10} limit listed in IX.H.3.b.i clearly states that condensable emissions are included, and the emission limits listed in that condition include values for condensable emissions.

6.0 Implementation Schedule

The requirements imposed on the Geneva Nitrogen are effective immediately. While some provision was made for sources generally to implement the RACT requirements of the PM2.5 SIP (and which were included as part of the modeled emission values for each source as discussed in that section above), the Geneva Nitrogen did not have any required RACT modifications to undertake. The emission limits listed in IX.H.2.p can be applied immediately. Similarly, the provisions of IX.H.1.a-f (the General Requirements) can also be applied immediately.

7.0 References

- Geneva Nitrogen, $PM_{2.5}$ SIP Major Point Source RACT Documentation – Geneva Nitrogen
- Geneva Nitrogen Approval Order DAQE-AN0825005-03
- Geneva Nitrogen Title V Operating Permit 4900082004
- Geneva Nitrogen Stack Test Results (2011-2015)
- $PM_{2.5}$ SIP adopted December 3, 2014 by Utah Air Quality Board

Evaluation Report – Geneva Nitrogen

UTAH PM_{10} SIP/MAINTENANCE PLAN

Utah County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report: PacifiCorp Energy – Lake Side Power Plant

Utah County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM10 SIP/MAINTENANCE PLAN EVALUATION REPORT
PacifiCorp Energy – Lake Side Power Plant

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.2 of the Utah Implementation Plan (SIP); to address the Utah County PM_{10} Nonattainment Area (UCNA). This document specifically serves as an evaluation of the PacifiCorp Energy operated Lake Side Power Plant.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law. In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Sections IX.H.1-4 of the 2005 State-only SIP will be repealed entirely, there is no need to refer to that document version within this report.
- When referencing the original SIP with an effective date of August 8, 1994 the qualifier $^{\{OS\}}$ will follow any citation from that document.
- In reference to the updated Utah County SIP with an effective date of January 22, 2003 the qualifier $^{\{UC\}}$ will follow any citation from that document.
- When referencing any new Maintenance Plan/SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

1.1 Facility Identification

Name: Lake Side Power Plant
Address: 1825 N Pioneer Lane, Vineyard, Utah, Utah County
Owner/Operator: PacifiCorp Energy
UTM coordinates: 4,464,500 m Northing, 436,000 m Easting, Zone 12

1.2 Facility Process Summary

The Lake Side Power Plant (LSPP) is a natural gas-fired electric generating plant consisting of four combined-cycle turbines, four heat recovery steam generators with duct burners, two auxiliary boilers, two cooling towers, one dew point heater, two diesel-fired emergency generators, and one diesel-fired fire pump. The plant is located in Utah County, which is part of the Provo, Utah $PM_{2.5}$ nonattainment area.

The plant is a Phase II acid rain source and a major source for $PM_{10}/PM_{2.5}$, NOx, CO, VOC, HAP and GHG emissions. The source (Block #1) was originally permitted as a PSD source and a PM10 non-attainment area major source. When Block #2 was added in 2011, this modification was permitted as a PSD major modification, as well as a PM10 nonattainment area major modification. Therefore, analysis of LAER was required on both occasions for the facility's PM_{10} and NOx emissions; analysis of BACT was required for all other emissions.

At the time of installation for both Block #1 and Block #2, BACT/LAER for the turbines was dry low-NOx burners, SCR and oxidation catalysts. The auxiliary boilers were fitted with dry low-NOx burners. The diesel equipment is required to operate on ultra-low sulfur diesel. The cooling towers have high-efficiency drift elimination.

1.3 Facility Criteria Air Pollutant Emissions Sources

The source consists of the following emission units:

One (1) natural gas-fired, dry low-NOx, combined-cycle turbine – CT #1
One (1) natural gas-fired, dry low-NOx, combined-cycle turbine – CT #2
One (1) natural gas-fired, dry low-NOx, combined-cycle turbine – CT #3
One (1) natural gas-fired, dry low-NOx, combined-cycle turbine – CT #4
One heat recovery steam generator, low-NOx duct burner, 184 MMBtu/hr – HRSG #1
One heat recovery steam generator, low-NOx duct burner, 184 MMBtu/hr – HRSG #2
One heat recovery steam generator, low-NOx duct burner, 400 MMBtu/hr – HRSG #3
One heat recovery steam generator, low-NOx duct burner, 400 MMBtu/hr – HRSG #4
Two (2) selective catalytic reduction systems with ammonia injection – Block #1 SCR
Two (2) selective catalytic reduction systems with ammonia injection – Block #2 SCR
Two (2) CO oxidation catalysts – Block #1 OxyCat
Two (2) CO oxidation catalysts – Block #2 OxyCat
One (1) natural gas-fired 61.2 MMBtu/hr auxiliary boiler – Aux Boiler #1
One (1) natural gas-fired 61.2 MMBtu/hr auxiliary boiler – Aux Boiler #2
Two (2) 1,500 hp diesel generators – Em Gen #1, #2
One (1) 3.67 MMBtu/hr diesel-fired fuel dew point heater – Heater #1
One (1) 290 hp diesel-fired fire pump – Pump #1
Cooling Towers #1, #2

1.4 Facility 2011 Baseline Actual Emissions and Current PTE

In 2011, LSPP's baseline actual emissions were determined to be the following (in tons per year):

Table 1: Actual Emissions

Pollutant	Actual Emissions (Tons/Year)
PM_{10}	31.7
SO_2	4.18
NO_x	86.47

The current PTE values for LSPP, as established by the most recent AO issued to the source (DAQE-AN130310012-15) are as follows:

Table 2: Current Potential to Emit

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	215.4
SO_2	55.6
NO_x	280.9

However, please see Section 2.0 (and Table 3) for further details on LSPP's PTE value.

2.0 Modeled Emission Values

Unlike the base year inventory, which used only the 2011 actual emissions for each source to set the baseline for modeling, a modified version of the PTE values was used for the modeled attainment demonstration. Beginning with the PTE values listed in Table 2 (from the most recent approval order issued to LSPP in 2015), these emissions were then "trued-up" by including the expected effects from implementation of RACT from the $PM_{2.5}$ SIP. This true-up yields a 2019 Projected Emission Value for each of the pollutants of concern. Where necessary, these values were further corrected for condensable particulates using simple correction factors based on fuel consumed or process type.

Where gaseous fuels such as natural gas were combusted, filterable-only emissions were converted to a filterable+condensable emission value by multiplying the filterable rate by 4. For natural gas, AP-42 lists the various emission factors as:

Filterable PM: 1.9 lb/106 scf
Condensable PM: 5.7 lb/106 scf
Total PM: 7.6 lb/106 scf

In other words, the total PM is almost exactly four times the filterable emission value. Liquid fuels, such as diesel fuel #2, were also converted using the latest AP-42 emission factors. Processes such as cooling towers, which emit largely filterable-only emissions, were not adjusted. Other processes were adjusted, as needed, on a case-by-case basis using the best data available – primarily the latest stack test information.

For the LSPP specifically, these additional steps were not required. As LSPP is a new "greenfield" source, the AO issued to LSPP in 2005 (and modified in 2011 to add Block #2) included both the application of BACT and LAER controls – the latter level of control being applied specifically for control of PM10, NOx and SO2 emissions. Thus, the plant was constructed with the assumption of RACT level control already in place. During the PM2.5 SIP process, this assumption proved true as no additional controls were imposed on this source. In addition, the source's emission limits for PM10 were set with the assumption that condensable PM10 was included; thus, all particulate limits are set as a filterable+condensable limit.

Therefore, for the LSPP, no change occurs between the values in Table 2 and the Modeled Emission Values listed in Table 3, as shown below:

Table 3: Modeled Emission Values

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	215.4
SO_2	55.6
NO_x	280.9

The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11-13 – which comprise the PM2.5 sections of the SIP. All requirements from the original PM10 SIP that have not been superseded or replaced, and which are still necessary, will also be retained. By necessary, meaning: significant from the standpoint of PM10 control, or in demonstrating that no backsliding in the application of RACT as viewed from the original SIP has taken place. This is discussed in greater detail in Item 3 below.

3.0 Comparison of Requirements – Original SIP and New Maintenance Plan

LSPP was never previously listed in the PM10 SIP. The plant began construction in 2005, more than ten years after the original SIP issuance and approval dates. Its construction was only possible using emission offset credits obtained from the closure and demolition of the Geneva Steel plant. In fact, where the LSPP facility is physically located is where a portion of the Geneva Steel plant once resided. The Utah County updated SIP{UC}, which still included Geneva Steel as a listed source, was issued and approved in 2002/2003, a full two years before the first permit was issued to LSPP authorizing construction.

However, LSPP is a listed source in the PM2.5 Section of the SIP (see SIP Section IX.H.13.c). As was discussed above in Item 2.0, all limits in this maintenance plan are based on the limits in the December 3, 2014 PM2.5 SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.13.c. Therefore a comparison only of the general requirements found in the Utah County updated SIP{UC} can be found below. For the source specific requirements, no direct comparison can be made.

3.1 Original SIP General Requirements

IX.H.1.a General Requirements{UC}

The original SIP was a divided document, having two separate sets of General Requirements. The requirements found at IX.H.1.a{OS} applied to the listed sources found in Utah County, while those found at IX.H.2.a{OS} applied to the listed sources found in Salt Lake and Davis County. Those original requirements were then fully superseded with the Utah County updated SIP{UC} issued in 2002 and made effective by EPA in January 2003. The comparison shown here is between the new maintenance plan and that most recent EPA-approved version.

1.a.A. Stack Testing{UC} – this subsection covered the general methods and procedures for conducting stack testing. As with the original SIP, it included the establishment of a pretest conference, and the use of specific EPA test methods. However, it lacked the establishment of a pretest protocol. This subsection has since been updated and superseded by SIP subsection IX.H.1.e which serves the same purpose.

1.a.B. Annual Emission Limitations{UC} – established that annual emissions would be determined on a rolling 12-month basis, and that a new 12 month emission total would be calculated on the first day of each month using the previous 12 months data. This subsection is no longer needed as the annual PM_{10} standard no longer exists, and no source-specific annual SIP Caps appear in either IX.H.2 or IX.H.3 of the new maintenance plan.

1.a.C. Recordkeeping Requirements{UC} – established that records need to be kept for all periods that the plant is in operation, for a period of at least two years, and provided upon request. This subsection has since been superseded by SIP subsection IX.H.1.c which serves the same purpose.

1.a.D. Proper Maintenance{UC} – established that all facilities need to be adequately and properly maintained. Not needed. This is inherent in the NSR permitting program, under R307-401-4(1).

1.a.E. Definitions{UC} – established that the definitions contained in R307 apply to Section IX.H.2. This subsection has since been superseded by SIP subsection IX.H.1.b which serves the same purpose.

1.a.F. Visible Emissions{UC} – covered the establishment of designated opacity limitations for specified process units and/or process equipment. This subsection has since been superseded by SIP subsection IX.H.1.f which serves the same purpose.

1.a.G. Visible Emissions (cont.){UC} – covered the procedure by which visible emission observations would be conducted. This subsection has since been superseded by SIP subsection IX.H.1.f which serves the same purpose.

1.a.H. Unpaved Operational Areas{UC} – established rules for treating fugitive dust with water sprays or chemical dust suppression. This requirement has been superseded by the nonattainment area fugitive dust rules of R307-309.

There were several additional subsections found in the original SIP for Utah County which did not appear in the Utah County updated SIP{UC}. These conditions were primarily outdated and no longer applicable. For the sake of completeness, they are included below.

1.a.F. Approval Orders{OS} – established that this subsection of the SIP superseded any previously issued AOs. No longer applicable, as this subsection of the SIP will be superseded, and no previously issued AOs are still in existence.

2.a.H. Future Modifications{OS} – established that future modifications to the approved facilities were also subject to the NSR permitting requirements. Not needed. This is inherent in the NSR permitting program, under R307-401-3(1)(b).

2.a.K. Test if Directed{OS} – established a definition of this term. No longer needed as this term is no longer used and the condition itself no longer applies. UDAQ has a minimum test frequency established under R307-165-2. This same rule also allows for (and requires) any additional testing to demonstrate compliance status as deemed necessary by the Director.

4.0 Discussion of Daily Emission Values

Table 4 is a comparison of annual PTE values with an expected daily (24-hour) emission value based on the short term limits found in IX.H.3.c.

Table 4: Comparison Table – New Maintenance Plan Emissions

All values in tons	SO_2	NO_x	PM_{10}
Annual	55.6	280.9	215.4[&]
Daily (24-hr)	-	1.7	0.75

[&] includes condensable emissions

There is no short term limit established for SO2 emissions given the low sulfur content of natural gas. The daily values listed for both NOx and PM10 include an allowance for startup and shutdown emissions. As 24-hour estimates, they are inherently higher values than simply dividing the annual emission values by 365. Also, these values are merely estimated values for comparison purposes, and are not to be viewed as SIP limitations. Those limits are found specifically in Section IX.H.3.c of the SIP.

5.0 New Maintenance Plan – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.1. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference. As specifically stated in subsection IX.H.1.a below, these general requirements apply to all sources subsequently listed in either IX.H.2 (Salt Lake County) or IX.H.3 (Utah County), and are in addition to (and in most cases supplemental to) any source-specific requirements found within those two subsections.

IX.H.1.a. This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

IX.H.1.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.1.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Both conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation. All conditions in these subsections are strictly in accordance with EPA approved methods and guidelines.

5.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.1.a through IX.H.1.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow – either in the Petroleum Refinery provisions of IX.H.1.g, or the source specific requirements of IX.H.2 and IX.H.3.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.1.e and IX.H.1.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.1.c.

5.2 Discussion of Attainment Demonstration

As is discussed above in Items 5.0 and 5.1, these are general conditions and have few if any specific limitations and requirements. Their inclusion here serves three purposes. 1. They act as a framework upon which the other requirements can build. 2. They demonstrate a prevention of backsliding. By establishing the same or functionally equivalent general requirements as were included in the original SIP, this demonstrates both that the original requirements have been considered, and either retained or updated/replaced as required. 3. When a general requirement

has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument can be made in that regard, the requirement was simply removed.

6.0 New Maintenance Plan – LSPP Specific Requirements

The LSPP specific conditions in Section IX.H.3 address those limitations and requirements that apply only to the LSPP Power Plant in particular.

IX.H.3.c.i This condition lists the specific requirements applicable to Block #1 Turbine/HRSG Stacks.

Subparagraph A: Emissions of NOx shall not exceed 14.9 lb/hr on a 3-hr basis.
Subparagraph B: Compliance with the above conditions shall be demonstrated as follows:
I. NOx monitoring shall be through use of a CEM as outlined in IX.H.1.f

IX.H.2.c.ii This condition lists the specific requirements applicable to Block #2 Turbine/HRSG Stacks.

Subparagraph A: Emissions of NOx shall not exceed 18.1 lb/hr on a 3-hr basis.
Subparagraph B: Compliance with the above conditions shall be demonstrated as follows:
I. NOx monitoring shall be through use of a CEM as outlined in IX.H.1.f

IX.H.2.j.iii This condition lists the startup/shutdown emission minimization plan requirements applicable to all three combustion turbines. The requirement also includes a definition of startup, shutdown, and a limit on total hours of operation (2) in startup or shutdown mode, per turbine, per day.

Subparagraph A: Limits applicable to Block #1 – total starts and shut down not to exceed 14 hours per day per turbine and 613.5 hours per 12-month rolling period, total NOx emissions from the Block #1 Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O2, transient load excursions limited to 160 hours per 12-month rolling period.
Subparagraph B: Limits applicable to Block #2 – total starts and shut down not to exceed 8 hours per day per turbine and 553.6 hours per 12-month rolling period, total NOx emissions from the Block #2 Turbine/HRSG Stacks shall not exceed 25 ppmvd at 15% O2, transient load excursions limited to 160 hours per 12-month rolling period.
Subparagraph C: Definitions – Startup, shutdown, transient load conditions, and a definition of operating day.

6.1 Monitoring, Recordkeeping and Reporting

Monitoring for IX.H.2.c.i.A and B is specifically outlined in IX.H.2.j.i.c; while IX.H.2.j.ii.A and B is addressed in IX.H.2.j.ii.C. Stack testing for PM10 is conducted annually, while NOx monitoring is covered by CEM. Procedures for PM10 testing are addressed under IX.H.1.e. CEM monitoring requirements are found in IX.H.1.f. Recordkeeping is subject to the requirements of IX.H.1.c.

6.2 Discussion of Attainment Demonstration

LSPP is primarily a source of NOx and direct PM10 emissions. While some SO2 emissions are added to the overall contribution from LSPP, it is a listed source because of NOx and PM10.

Although not listed in the original PM10 SIP, and not included in the Utah County updated SIP, the LSPP remains viable within the maintenance plan through R307-403-5 – Offsets: PM10 Nonattainment Areas. When the LSPP was originally authorized for construction, and again during the 2011 expansion to install Block #2, the owner/operator PacifiCorp Energy was required to produce and use emission offset credits as outlined under R307-403-5(1)(b).

Specifically, as both the initial installation and the expansion were both larger than the 50 ton per year threshold listed in that rule, the offset credits needed to be obtained at a ratio of 1.2:1. These offset credits also satisfied the emission offsetting requirement of 40 CFR 51.165(a)(9)(i). The emission offset credits used were generated from the closure of the Geneva Steel plant (emission credit pedigree available upon request); a source listed in both the original SIP and the Utah County updated SIP. Therefore, the emission increase associated with the installation of the LSPP was already included in the background emissions of the airshed and at a greater emissions ratio.

7.0 Implementation Schedule

For the most part, the requirements imposed on the LSPP are effective immediately. While some provision was made for sources generally to implement the RACT requirements of the PM2.5 SIP (and which were included as part of the modeled emission values for each source as discussed in that section above), the LSPP did not have any required RACT modifications to undertake. The emission limits listed in IX.H.3.c can be applied immediately. Similarly, the provisions of IX.H.1.a-f (the General Requirements) can also be applied immediately.

8.0 References

Evaluation Report – LSPP Power Plant

UTAH PM_{10} SIP/MAINTENANCE PLAN

Salt Lake County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report: Payson City Power Plant

Utah County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
Payson City Power Plant

1.0 Introduction

The following is part of the Technical Support Documentation for Section IX, Part H.1 and Section IX, Part H.2 of the Utah SIP; to address the Utah County PM_{10} Nonattainment Area. This document specifically serves as an evaluation of the Payson City Power Plant.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed without replacement, as this section is no longer needed.

This evaluation report references the SIP version originally dated June 28, 1991 (updated November 4, 1992 and made effective by EPA on August 8, 1994). This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law.

In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Section IX.H of the 2005 State-only SIP will be repealed entirely and will not be referred to in this report.
- When referencing the original SIP with an effective date of August 8, 1994 the qualifier $^{\{OS\}}$ will follow any citation from that document.
- In reference to the updated Utah County SIP with an effective date of January 22, 2003 the qualifier $^{\{UC\}}$ will follow any citation from that document.
- When referencing any new SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

2.0 Facility Identification

Name: Payson City Power Plant
Address: 1100 North 100 East, Payson, Utah, Utah County
Owner/Operator: Payson City Corporation
UTM coordinates: 4,432,650 m Northing, 437,060 m Easting, Zone 12

3.0 Facility Process Summary

Payson City Corporation operates the Payson City Power Plant (PCPP) a peaking power plant consisting of four dual-fuel internal combustion (IC) engines. Engines #1 and #2 are rated at 2,650 kW each. Engine #3 is rated at 2,093 kW, while engine #4 is rated at 1,800 kW. The site also consists of a small emergency generator (186 hp), a small natural gas-fired boiler (0.812 MMBtu/hr), and several above-ground storage tanks. A grandfathered emergency flare acts as a safety device during tank filling operations. Two cooling towers cool the exhaust from the IC engines.

The power plant is operated as a peaking and supplemental power plant to provide electrical power to municipal power customers in and around the City of Payson. The plant is defined as a Title V major source located in Utah County, and within the Provo, Utah $PM_{2.5}$ nonattainment area.

Operation of the plant is dependent on local demand and cost of utility power. The IC engines operate primarily on natural gas, with ultra-low sulfur diesel fuel used for start-up.

4.0 Facility Criteria Air Pollutant Emissions Sources

The facility consists of the following emission sources

- 2,650 kW dual-fuel fired IC engine (IC #1)
- 2,650 kW dual-fuel fired IC engine (IC #2)
- 2,093 kW dual-fuel fired IC engine (IC #3)
- 1,800 kW dual-fuel fired IC engine (IC #4)
- 0.812 MMBtu/hr natural gas-fired boiler (boiler #1)
- Diesel and glycol storage tanks (tanks)
- Emergency flare (flare)
- 186 hp emergency generator (Em Gen)
- Cooling towers (cooling towers #1, #2)

5.0 Facility 2011 Baseline Actual Emissions and Current PTE

PCPP operates sporadically as a peaking plant and as a part of the general municipal power generator network resulting in low actual emissions compared to its potential to emit for all pollutants.

Table 1: Comparison of Actual and Potential Emissions

Pollutant	Actual Emissions (Tons/Year)[1]	Potential to Emit (Tons/Year)[2]
PM_{10}	0.09	25.00
SO_2	0.08	3.30
NO_x	3.85	200.00

[1] PCPP's 2011 actual emissions
[2] PTE's for PCPP's AO issued DAQE-AN108230006-14, dated July 7, 2014

6.0 Projected Emissions for 2019

A modified version of the PTE values was used in the modeled attainment demonstration. The projected emission values for 2019 were calculated from limits given in PCPP's current AO and the $PM_{2.5}$ SIP. PCPP was limited to 200 and 44.8 tons per year of NO_x and CO, respectively, for IC #1-4. Based on the emissions from the IC engines, the CO emission limit compared to the actual emissions limited the engine operation compared to the NO_x emission limit compared to the actual emissions. A scaling factor was determined from the actual IC 1-4 CO emissions and the emission limit, which was then used to scale the other pollutants of interest.

Table 3: 2019 Projected Emission Values or Modeled Emission Values

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	1.10
SO_2	1.96
NO_x	99.20

7.0 Maintenance Plan

PCPP was not a previously listed SIP source in the 1994 Original SIP$^{\{OS\}}$ or the 2003 Utah County SIP$^{\{UC\}}$. However, PCPP is not a new source. Potential emissions from PCPP were less than the threshold that required inclusion in either the Original or Utah County SIPs. PCPPs emissions were included in the modeling efforts associated with these SIPs.

8.0 New Maintenance Plan – General Requirements

The updated general requirements for all listed sources are found in SIP Subsection IX.H.1. This serves as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference.

Conditions 1.a, 1.b and 1.d are declaratory statements and define the framework of the other SIP

conditions. They have little in the way of compliance provisions. Condition 1.c is the primary recordkeeping requirement and is further discussed in section 4.2. Conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

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

Limit Discussion

This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.1.b The definitions contained in R307-101-2, Definitions, apply to Section IX, Part H.

Limit Discussion

This requirement states that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

IX.H.1.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.

Limit Discussion

This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

IX.H.1.d All emission limitations listed in Subsections IX.H.2 and IX.H.3 apply at all times, unless otherwise specified in the source specific conditions listed in IX.H.2 and 3.

Limit Discussion

This requirement states that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

IX.H.1.e Stack Testing:

i. As applicable, stack testing to show compliance with the emission limitations for the sources in Subsection IX.H.2 and 3 shall be performed in accordance with the following:

A. Sample Location: The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other EPA-approved methods acceptable to the Director.

B. Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2 or other EPA-approved testing methods acceptable to the Director.

C. PM_{10}: 40 CFR 51, Appendix M, Methods 201a and 202, or other EPA approved testing methods acceptable to the Director. If a method other than 201a is used, the portion of the front half of the catch considered PM_{10} shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.

D. SO_2: 40 CFR 60 Appendix A, Method 6C or other EPA-approved testing methods acceptable to the Director.

E. NO_x: 40 CFR 60 Appendix A, Method 7E or other EPA-approved testing methods acceptable to the Director.

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

G. A stack test protocol shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by the Director. The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, and Occupational Safety and Health

Administration (OSHA) approvable access shall be provided to the test location.

H. The production rate during all compliance testing shall be no less than 90% of the maximum production rate achieved in the previous three (3) years. If the desired production rate is not achieved at the time of the test, the maximum production rate shall be 110% of the tested achieved rate, but not more than the maximum allowable production rate. This new allowable maximum production rate shall remain in effect until successfully tested at a higher rate. The owner/operator shall request a higher production rate when necessary. Testing at no less than 90% of the higher rate shall be conducted. A new maximum production rate (110% of the new rate) will then be allowed if the test is successful. This process may be repeated until the maximum allowable production rate is achieved.

Limit Discussion

This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

IX.H.1.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.

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

Limit Discussion

This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

9.0 SCC Specific Requirements

The PCPP specific conditions in Section IX.H.2 address those limitations and requirements that apply only to PCPP.

IX.H.3.e Payson City Corporation: Payson City Power

i. Emissions of NO_x shall be no greater than 1.54 ton per day for all engines combined.

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

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

A. The NO_x emission factor for each engine shall be derived from the most recent stack test. Stack tests shall be performed in accordance with IX.H.1.e. Each engine shall be tested at least every three years from the previous test.

B. NO_x emissions shall be calculated on a daily basis.

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

D. The number of kilowatt hours generated by each engine shall be recorded on a daily basis with an electrical meter.

Limit Discussion

PCPP is limited to a combined 1.54 tons per day of NO_x. The condition also includes the definition of a day as being from midnight until the following midnight. Compliance shall be determined daily with the use of emission factors determined from stack tests and generator output. The equations to be used for the emission calculations are also included. Stack testing has already been completed and emission factors determined from this sampling will be used in place of an initial stack test.

PCPP was not previously included in the Original or Utah County SIP; therefore, limits from previous SIPs have not been altered.

10.0 Monitoring, Recordkeeping and Reporting

Monitoring requirements are found in the general requirement IX.H.1.e and all common recordkeeping and reporting provisions have been consolidated in the general requirements under IX.H.1.c.

Monitoring of the NO_x emission limit, IX.H.3.g.i, is determined by maintaining daily records of emissions. The emissions are determined from data gathered from the engine's stack test and the power generated by that engine.

11.0 Discussion of Attainment Demonstration

The emission threshold to include a source in the PM_{10} SIP was lowered compared to those for 2003 Utah County {UC} or the 1994 original SIPs{OS}. Backsliding by this source has been prevented, as it was previously not included in the SIP.

12.0 Emission Limits

Annual and daily emissions are given below.

Table 4: Yearly Emissions and Daily Emissions Limits

All values in tons	**NO_x**
Annual	200
Daily (24-hr)	1.54

8.0 Reference

Evaluation Report –

UTAH PM_{10} SIP/MAINTENANCE PLAN

Utah County Nonattainment Area

Supporting Information

PM_{10} SIP/Maintenance Plan Evaluation Report: Provo City Power – Power Plant

Utah County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} /SIP/MAINTENANCE PLAN EVALUATION REPORT
Provo City Power – Power Plant

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.3 of the Utah Maintenance Plan; to address the Utah County PM_{10} Nonattainment Area. This document specifically serves as an evaluation of the Payson City Power Plant.

Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, and made effective by EPA on August 8, 1994. This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and therefore never became federal law.

In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Section IX.H of the 2005 State-only SIP will be repealed entirely and will not be referred to in this report.
- When referencing the original SIP with an effective date of August 8, 1994 the qualifier $^{\{OS\}}$ will follow any citation from that document.
- In reference to the updated Utah County SIP with an effective date of January 22, 2003 the qualifier $^{\{UC\}}$ will follow any citation from that document.
- When referencing any new SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

2.0 Facility Identification

Name: Provo City Power – Power Plant
Address: 702 North 300 West, Provo, Utah, Utah County
Owner/Operator: Provo City Power
UTM coordinates: 443,455 East 4,454,710 North Zone 12

3.0 Facility Process Summary

Provo City Power (PCP) operates a power plant consisting of four 2,585 kW dual-fuel internal combustion (IC) engines. There are also four diesel day-tanks and an emergency generator located on site. The plant is operated as a peaking and supplemental power plant to provide electrical power to municipal power customers in and around the City of Provo. PCP is defined as a Title V major source located in Utah County, and within the Provo, Utah $PM_{2.5}$ nonattainment area.

Operation of the plant is dependent on local demand and cost of utility power. The IC engines operate primarily on natural gas, with ultra-low sulfur diesel fuel used for startup.

4.0 Facility Criteria Air Pollutant Emissions Sources

The facility consists of the following emission sources

- 2,585 kW dual-fuel fired IC engine (IC #1)
- 2,585 kW dual-fuel fired IC engine (IC #2)
- 2,585 kW dual-fuel fired IC engine (IC #3)
- 2,585 kW dual-fuel fired IC engine (IC #4)
- Diesel day-tank #1
- Diesel day-tank #2
- Diesel day-tank #3
- Diesel day-tank #4
- Emergency generator (Em Gen)

5.0 Facility 2011 Baseline Actual Emissions and Current PTE

PCP operates sporadically as a peaking plant and as a part of the general municipal power generator network resulting in low actual emissions compared to its potential to emit for all pollutants.

Table 1: Comparison of Actual and Potential Emissions

Pollutant	Actual Emissions (Tons/Year)[1]	Potential to Emit (Tons/Year)[2]
PM_{10}	0.07	14.50
SO_2	<0.01	4.00
NO_x	5.24	254.00

[1] PCP's 2011 actual emissions
[2] PTE's for PCP's AO issued DAQE-AN107950012-15, dated May 6, 2015

6.0 Projected Emissions for 2019

A modified version of the PTE values was used in the modeled attainment demonstration. The projected emission values for 2019 were calculated from limits given in PCP's current AO, the $PM_{2.5}$ SIP, and the 2011 inventory submittal. PCP is limited to 254 tons per year of NO_x for all engines combined (IC #1-4). The engines are started with diesel and fueled the remaining time with natural gas. It was assumed that the engines would be fueled by diesel for the equivalent amount of time in 2019 as in 2011. The engines were then allowed to operate equivalently until the 254 tons per year NO_x limit was reached.

Table 3: 2019 Projected Emission Values or Modeled Emission Values

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	2.00
SO_2	0.09
NO_x	254

7.0 Comparison of Requirements – Original SIP and New Maintenance Plan

PCP is a previously listed SIP source. In the original PM_{10} SIP document for Utah County, requirements and limits for Provo City Power are found in IX.1.2.J{OS}. In the 2003 Utah County SIP, requirements and limits for Provo City Power are found in I.1.b.D {UC}.

Although a specific application of new RACT analysis is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent $PM_{2.5}$ Section of the SIP. This section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM_{10} SIP sources. The conditions, requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11, IX.H.12 and IX.H.13 – which comprise the $PM_{2.5}$ sections of the SIP, and include this additional RACT application. All requirements from the original PM_{10} SIP that have not been superseded or replaced, and which are still necessary, will also be retained. By necessary, meaning: needed in the demonstration of attainment of the 24-hour standard, or in demonstrating that no backsliding in the application of RACT has taken place.

All limits in this maintenance plan are based on the limits in the $PM_{2.5}$ SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.k. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below.

7.1 2002 SIP General Requirements

The following is a list of the requirements from the Utah County {UC} SIP. A discussion of the requirements including current relevance and expected changes is included.

IX.H.1.a General Requirements {UC}

Requirement IX.H.1.a.A. Stack Testing{UC} – this subsection covered the general methods and procedures for conducting stack testing for PM_{10}, SO_2, and NO_x, including the establishment of a pretest protocol, pretest conference, the use of specific EPA test methods, and acceptable production video.

Discussion This subsection has since been updated and superseded by SIP subsection IX.H.1.e which incorporates equivalent language.

Requirement IX.H.1.a.B Compliance with Annual Limitations {UC} – Compliance with the annual limitations shall be determined based on a rolling 12 month total. On the first day of each month a new 12-month total shall be calculated using the previous 12 months.

Discussion This limitation is no longer needed as the annual PM_{10} standard no longer exists. Daily limits are expected to be included in the source specific sections of the SIP. Also, no source-specific annual SIP Caps appear in either IX.H.2 or IX.H.3 of the revised SIP.

Requirement IX.1.a.C Recordkeeping Requirements{UC} – Records of all information used to show compliance shall be kept for all periods when the plant is in operation. These records shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request. This recordkeeping requirement includes records of startup/shutdown implementation procedures, as well as CEMS testing data and stack testing data, as applicable.

Discussion This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

Requirement IX.1.a.D Proper Maintenance {UC} – established that all facilities need to be adequately and properly maintained.

Discussion This is inherent in the NSR permitting program and is no longer needs to be included.

Requirement IX.1.a.E Definitions {UC} – The definitions contained in R307-101-2, Definitions, apply to Section IX. Part H.

Discussion This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

Requirement IX.1.a.F Visible Emission Limitations {UC} –Visible emissions shall be as follows except as otherwise designated in specific source subsections: Baghouse applications shall not exceed 10% opacity; scrubber and ESP applications shall not exceed 15% opacity; combustion sources without control facilities shall not exceed 10% opacity; and fugitive emissions shall not exceed 15% opacity; fugitive dust and all other sources shall not exceed 20% opacity.

Discussion This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

Requirement IX.1.a.G Opacity Observations {UC} - Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9. For intermittent sources and mobile sources opacity observations shall be conducted using procedures similar to Method 9, but the requirement for observations to be made at 15 second intervals over a six minute period shall not apply and any time interval with no visible emissions shall not be included.

Discussion This subsection has since been superseded by SIP subsection IX.H.1.f, which incorporates equivalent language.

Requirement IX.1.a.H Control of Fugitive Dust from Mobile Equipment - All unpaved operational areas which are used by mobile equipment shall be water sprayed and/or chemically treated to reduce fugitive dust. Control is required at all times (24 hours per day every day) for the duration of the project/operation. The application rate of water shall be a minimum of 0.25 gallons per square yard. Application shall be made at least once every two hours during all times the installation is in use unless daily rainfall exceeds .10 of an inch or the road is in a muddy condition or if it is covered with snow or if the ambient temperature falls below freezing or if the surfaces are in a moist/damp condition. If chemical treatment is to be used, the plan must be approved by the Executive Secretary. Records of water treatment shall be kept for all periods when the plant is in operation. The records shall include the following items:

A. Date
B. Number of treatments made, dilution ratio, and quantity
C. Rainfall received, if any, and approximate amount
D. Time of day treatments were made

Records of treatment shall be made available to the Executive Secretary upon request and shall include a period of two years ending with the date of the request.

Discussion PCP will be required to comply with the most recently EPA approved Fugitive Emissions and Fugitive Dust rule.

7.2 SIP Source Specific Requirements

PCP specific limits and requirements from the 2003 Utah County SIP{UC} are given below.

IX.1.b.E Provo City Power

IX.1.b.D.1. NO_x emissions from the operation of all engines and boilers at the plant shall not exceed 2.45 tons per day.

The following equation shall be used to calculate the daily emissions from each engine:

(Power production in kW-hr/day) x (Emission rate in gram/kW-hr) x (1 lb/453.59 g) x (1 ton/2000 Ibs) = tons/day.

IX.1.b.D.2. NO_x emissions from the operation of all engines and boilers at the plant shall not exceed 254 tons per year.

The following equation shall be used to calculate the annual emissions from each engine:

(Power production in kW-hr/rolling 12-month period) x (Emission rate in gram/kW-hr) x (1 lb/453.59 g) x (1 ton/2000 Ibs) =tons/yr

This is the same limit that is in the Utah County SIP[uc].

IX.1.b.D.3. Stack testing to show compliance with the above NO_x emission limitations and to update the emission rate factor used in Conditions 1 and 2 above shall be performed as follows:

Boiler No.4 and Boiler No.5 shall each be tested every 8,760 hours of operation arid at least once every three years.

Each engine shall be tested every 8,760 hours of operation and at least every three years.

IX.1.b.D.4. Total plant emissions shall be the sum of emissions from each of engines and boilers. The emission rates to be used in the equations listed in conditions 1 and 2 above shall be the most recent stack test results. Power production rates shall be determined by Watt Hour meters on each of

engine and boiler generators. The total amount of kilowatt-hours generated by each engine or boiler shall be recorded on both a daily and a monthly basis.

Limit Discussion
The limits reference boilers that have been removed from PCP, have been removed from the source and will be removed in the updated SIP. The yearly limit, IX.1.b.D.2., is no longer applicable to the PM_{10} SIP; a 24 hour NAAQS now applies. This requirement will be removed from with the updated SIP. Additionally, the stack testing frequency for the engines will be increased to at least once every three years.

7.3 New Maintenance Plan – General Requirements

General requirements have been updated from the Utah County SIP {UC} and are included in the following discussion. The updated general requirements for all listed sources are found in SIP Subsection IX.H.1. This serves as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference.

Conditions 1.a, 1.b and 1.d are declaratory statements and define the framework of the other SIP conditions. They have little in the way of compliance provisions. Condition 1.c is the primary recordkeeping requirement and is further discussed in section 4.2. Conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

Requirement This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements that the source specific requirements take precedence.

Discussion This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

Requirement IX.H.1.b The definitions contained in R307-101-2, Definitions, apply to Section IX, Part H.

Discussion This requirement states that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

Requirement IX.H.1.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.

Discussion This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

Requirement IX.H.1.d All emission limitations listed in Subsections IX.H.2 and IX.H.3 apply at all times, unless otherwise specified in the source specific conditions listed in IX.H.2 and 3.

Discussion This requirement states that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3. There may be conditions that

It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.2 or IX.H.3.

Requirement IX.H.1.e Stack Testing:

i. As applicable, stack testing to show compliance with the emission limitations for the sources in Subsection IX.H.2 and 3 shall be performed in accordance with the following:

A. Sample Location: The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other EPA-approved methods acceptable to the Director.

B. Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2 or other EPA-approved testing methods acceptable to the Director.

C. PM_{10}: 40 CFR 51, Appendix M, Methods 201a and 202, or other EPA approved testing methods acceptable to the Director. If a method other than 201a is used, the portion of the front half of the catch considered PM_{10} shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.

D. SO_2: 40 CFR 60 Appendix A, Method 6C or other EPA-approved testing methods acceptable to the Director.

E. NO_x: 40 CFR 60 Appendix A, Method 7E or other EPA-approved testing methods acceptable to the Director.

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

G. A stack test protocol shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by the Director. The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, and Occupational Safety and Health Administration (OSHA) approvable access shall be provided to the test location.

H. The production rate during all compliance testing shall be no less than 90% of the maximum production rate achieved in the previous three (3) years. If the desired production rate is not achieved at the time of the test, the maximum production rate shall be 110% of the tested achieved rate, but not more than the maximum allowable production rate. This new allowable maximum production rate shall remain in effect until successfully tested at a higher rate. The owner/operator shall request a higher production rate when necessary. Testing at no less than 90% of the higher rate shall be conducted. A new maximum production rate (110% of the new rate) will then be allowed if the test is successful. This process may be repeated until the maximum allowable production rate is achieved.

Discussion This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

Requirement IX.H.1.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.

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

Discussion This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

Limit Discussion

This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

7.4 New Maintenance Plan – PCP Specific Requirements

IX.H.3. e Provo City Power: Power Plant

i. NO_x emissions from the operation of all engines at the plant shall not exceed 2.45 tons per day.

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

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

a. The NO_x emission factor for each engine shall be derived from the most recent stack test. Stack tests shall be performed in accordance with IX.H.1.e. Each engine shall be tested every 8,760 hours of operation or at least every three years from the previous test, whichever occurs first.

b. NO_x emissions shall be calculated on a daily basis.

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

d. The number of kilowatt hours generated by each engine shall be recorded on a daily basis with an electrical meter.

Limit Discussion

PCP is limited to 2.45 tons per day of NO_x with stack tests every three years to verify emission factors. Stack testing has already been completed and emission factors determined from this sampling will be used in place of an initial stack test. The condition also includes the definition of a day as being from midnight until the following midnight. Also, the boiler references were removed from the limits, as they have been removed.

8.0 Monitoring, Recordkeeping and Reporting

Monitoring requirements are found in the general requirement IX.H.1.e and all common recordkeeping and reporting provisions have been consolidated in the general requirements under IX.H.1.c.

Monitoring of the NO_x emission limit, IX.H.3.g.i, is determined by maintaining daily records of emissions. The emissions are determined from data gathered from the engine's stack test and the power generated by that engine.

9.0 Discussion of Attainment Demonstration

The general requirements act as a framework upon which the other requirements can build. Second, they demonstrate a prevention of backsliding. Through the use of general requirements that are either the same as or functionally equivalent to those in the 2003 Utah County SIP, backsliding has been prevented. Finally, when a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention

would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument could be made in that regard, the requirement was simply removed.

The source specific limits are equivalent to the requirements from the 2003 Utah County SIP. Requirements that were removed included the yearly NO_x emission limits, as there is no yearly standard. Monitoring, recordkeeping, and reporting requirements were updated with an increased stack testing frequency.

10.0 Implementation Schedule

The requirements imposed on the PCP are effective immediately. PCP did not have any required RACT modifications to undertake from the $PM_{2.5}$ SIP RACT requirements. The emission limits listed in IX.H.3.g can be applied immediately. Similarly, the general requirements, IX.H.1.a-f, can also be applied immediately.

11.0 Emission Limits

Annual and daily emissions are given below.

Table 4: Yearly Emissions and Daily Emission Limits

All values in tons	NO_x
Annual	254.00{uc}
Daily (24-hr)	2.45

7.0 References

To be included with final version

Evaluation Report –

UTAH PM_{10} SIP/MAINTENANCE PLAN

Utah County Nonattainment Area

Supporting Information

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PM_{10} SIP/Maintenance Plan Evaluation Report: Springville City Corporation- Whitehead Power Plant

Utah County Nonattainment Area

Utah Division of Air Quality

Major New Source Review Section

October 1, 2015

PM_{10} SIP/MAINTENANCE PLAN EVALUATION REPORT
Springville City Corporation

1.0 Introduction

This evaluation report (report) provides Technical Support for Section IX, Part H.1 and Section IX, Part H.3 of the Utah Maintenance Plan; to address the Utah County PM_{10} Nonattainment Area. This document specifically serves as an evaluation of the Springville City Corporation.

> Note on document identification: The intention of the Utah Division of Air Quality is to develop a Maintenance Plan to address PM_{10}. As part of this effort, SIP Subsections IX.H.1 Emission Limits and Operating Practices – General Requirements, IX.H.2 Source-Specific Particulate Emission Limitations in Salt Lake and Davis Counties and IX.H.3 Source-Specific Particulate Emission Limitations for Utah County will be repealed and replaced. Subsection IX.H.4 will be repealed and replaced with Interim Emission Limits and Operating Practices. This subsection provides interim limits, consistent with the limits codified in the $PM_{2.5}$ SIP, until future controls have been implemented within timeframes identified in Section IX Part H.2.

This evaluation report references the SIP version originally dated June 28, 1991 and made effective by EPA on August 8, 1994). This SIP version is often referred to as the "original SIP." The Utah County portion of the SIP was further updated on June 5, 2002 and made effective by EPA on January 22, 2003. Additional SIP revisions were adopted by the Air Quality Board on July 6, 2005 and became state law on August 1, 2005. However, this version of the SIP was not adopted by EPA and, therefore, never became federal law.

In order to distinguish between the various documents in this report, the following coding scheme will be used:

- Since Section IX.H of the 2005 State-only SIP will be repealed entirely and will not be referred to in this report.
- When referencing the original SIP with an effective date of August 8, 1994 the qualifier $^{\{OS\}}$ will follow any citation from that document.
- In reference to the updated Utah County SIP with an effective date of January 22, 2003 the qualifier $^{\{UC\}}$ will follow any citation from that document.
- When referencing any new SIP condition or requirement, the citation will be left blank.

Therefore, a particular sentence of this document might read as follows:

SIP Subsection IX.H.1.c – Stack Testing supersedes 2.a.A$^{\{OS\}}$ from the original SIP.

2.0 Facility Identification

Name: Springville City Corporation
Address: 50 South Main, Srpingville, Utah, Utah County
Owner/Operator: Springville City Corporation
UTM coordinates: 4,446,000 m Northing, 448,300 m Easting, Zone 12

3.0 Facility Process Summary

Springville City Corporation (SCC) operates Whitehead Power Plant, a peaking and supplemental power plant consisting of seven dual-fuel internal combustion (IC) engines. Engines #1, #2, and #3 are rated at 7.0 MW each; engine #4 is rated at 5.1 MW; and engines #5, #6 and #7 are rated at 2.7 MW each. There are also two small boilers on site. One is fired on natural gas (6.0 MMBtu/hr), while the second is fired on digester gas (2.5 MMBtu/hr). Finally three storage tanks hold diesel fuel for startup of the engines.

The power plant provides electrical power to municipal power customers in and around the City of Springville. The plant is defined as a Title V major source located in Provo City within Utah County. In addition to being located in the nonattainment area for PM_{10}, it is also located within the nonattainment area for $PM_{2.5}$ and the CO maintenance area.

Operation of the plant is dependent on local demand and cost of utility power. The IC engines operate primarily on natural gas, with ultra-low sulfur diesel fuel used for startup.

4.0 Facility Criteria Air Pollutant Emissions Sources

The facility consists of the following emission sources

- 7.0 MW dual-fuel fired IC engine (IC #1)
- 7.0 MW dual-fuel fired IC engine (IC #2)
- 7.0 MW dual-fuel fired IC engine (IC #3)
- 5.1 MW dual-fuel fired IC engine (IC #4)
- 2.7 MW dual-fuel fired IC engine (IC #5)
- 2.7 MW dual-fuel fired IC engine (IC #6)
- 2.7 MW dual-fuel fired IC engine (IC #7)
- 6.0 MMBtu/hr natural gas-fired boiler (boiler #1)
- 2.5 MMBtu/hr digester (methane) gas-fired boiler (boiler #2)
- Diesel storage tanks (tanks 1-3)

5.0 Facility 2011 Baseline Actual Emissions and Current PTE

SCC operates as a peaking and supplemental power plant resulting in low actual emissions compared to its Potential to Emit for all pollutants.

Table 1: Comparison of Actual and Potential Emissions

Pollutant	Actual Emissions (Tons/Year)[1]	Potential to Emit (Tons/Year)[2]
PM_{10}	0.03	2.50
SO_2	<0.01	3.21
NO_x	0.60	248.00

[1] SCC's 2011 actual emissions
[2] PTE's for SCC's AO issued DAQE-AN0819007-03, dated December 30, 2003

6.0 Projected Emissions for 2019

A modified version of PTE values were used in the modeled attainment demonstration. The projected emission values for 2019 were calculated from limits given in SCC's current AO, the $PM_{2.5}$ SIP and the submitted inventory emission estimates. SCC was limited to 248 tons per year of NOx and 200 tons per year of CO. NO_x emissions are the limiting factor between these two limits. Emissions from the 2011 and 2008 inventory submittals were used to calculate emission factors that were used to increase emissions to the NO_x limit. It was assumed that the engines were fired with diesel for 10 % of the operational time and that natural gas was used for the remaining operational time. Finally, it was assumed that 5.1 MW dual-fuel IC engine was operated preferentially for 8760 hours per year. For the remaining time, the three (3) 7.0 MW dual-fuel IC engines were operated.

Table 3: 2019 Projected Emission Values or Modeled Emission Values

Pollutant	Potential to Emit (Tons/Year)
PM_{10}	5.74
SO_2	0.41
NO_x	248.00

7.0 Comparison of Requirements – Original SIP and New Maintenance Plan

SCC is a previously listed SIP source. In the original PM_{10} SIP document for Utah County, requirements and limits for Springville City Power are found in IX.1.2.L$^{\{OS\}}$. In the 2003 Utah County SIP, requirements and limits for Springville City Corporation are found in I.1.b.D $^{\{UC\}}$.

Although a specific application of new RACT analysis is not a requirement of the maintenance plan, the limitations found within this maintenance plan are based on the most recent $PM_{2.5}$ Section of the SIP. This section of the SIP required the application of RACT above and beyond the existing controls already required of most listed PM_{10} SIP sources. The conditions,

requirements and emission limitations contained within this maintenance plan are based on those in Sections IX.H.11, IX.H.12 and IX.H.13 – which comprise the $PM_{2.5}$ sections of the SIP, and include this additional RACT application. All requirements from the original PM_{10} SIP that have not been superseded or replaced, and which are still necessary, will also be retained. By necessary, meaning: needed in the demonstration of attainment of the 24-hour standard, or in demonstrating that no backsliding in the application of RACT has taken place.

All limits in this maintenance plan are based on the limits in the $PM_{2.5}$ SIP; either in the general requirements of subsection IX.H.11 or the source specific requirements of IX.H.12.k. Therefore, a comparison between the original SIP requirements, and those found in this new maintenance plan can be found below.

7.1 2002 SIP General Requirements

The following is a list of the requirements from the Utah County {UC} SIP. A discussion of the requirements including current relevance and expected changes is included.

IX.H.1.a General Requirements {UC}

Requirement IX.H.1.a.A. Stack Testing{UC} – this subsection covered the general methods and procedures for conducting stack testing for PM_{10}, SO_2, and NO_x, including the establishment of a pretest protocol, pretest conference, the use of specific EPA test methods, and acceptable production video.

Discussion This subsection has since been updated and superseded by SIP subsection IX.H.1.e which incorporates equivalent language.

Requirement IX.H.1.a.B Compliance with Annual Limitations {UC} – Compliance with the annual limitations shall be determined based on a rolling 12 month total. On the first day of each month a new 12-month total shall be calculated using the previous 12 months.

Discussion This limitation is no longer needed as the annual PM_{10} standard no longer exists. Daily limits are expected to be included in the source specific sections of the SIP. Also, no source-specific annual SIP Caps appear in either IX.H.2 or IX.H.3 of the new maintenance plan.

Requirement IX.1.a.C Recordkeeping Requirements{UC} – Records of all information used to show compliance shall be kept for all periods when the plant is in operation. These records shall be made available to the Executive Secretary upon request, and shall include a period of two years ending with the date of the request. This recordkeeping requirement includes records of startup/shutdown implementation procedures, as well as CEMS testing data and stack testing data, as applicable.

Discussion This subsection has since been superseded by SIP subsection IX.H.1.c which incorporates equivalent language.

Requirement IX.1.a.D Proper Maintenance {UC} – established that all facilities need to be adequately and properly maintained.

Discussion This is inherent in the NSR permitting program and is no longer needs to be included.

Requirement IX.1.a.E Definitions {UC} – The definitions contained in R307-101-2, Definitions, apply to Section IX. Part H.

Discussion This subsection has since been superseded by SIP subsection IX.H.1.b which incorporates equivalent language.

Requirement IX.1.a.F Visible Emission Limitations {UC} –Visible emissions shall be as follows except as otherwise designated in specific source subsections: Baghouse applications shall not exceed 10% opacity; scrubber and ESP applications shall not exceed 15% opacity; combustion sources without control facilities shall not exceed 10% opacity; and fugitive emissions shall not exceed 15% opacity; fugitive dust and all other sources shall not exceed 20% opacity.

Discussion This subsection has since been superseded by SIP subsection IX.H.1.f which incorporates equivalent language.

Requirement IX.1.a.G Opacity Observations {UC} - Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9. For intermittent sources and mobile sources opacity observations shall be conducted using procedures similar to Method 9, but the requirement for observations to be made at 15 second intervals over a six minute period shall not apply and any time interval with no visible emissions shall not be included.

Discussion This subsection has since been superseded by SIP subsection IX.H.1.f, which incorporates equivalent language.

Requirement IX.1.a.H Control of Fugitive Dust from Mobile Equipment - All unpaved operational areas which are used by mobile equipment shall be water sprayed and/or chemically treated to reduce fugitive dust. Control is required at all times (24 hours per day every day) for the duration of the project/operation. The application rate of water shall be a minimum of 0.25 gallons per square yard. Application shall be made at least once every two hours during all times the installation is in use unless daily rainfall exceeds .10 of an inch or the road is in a

muddy condition or if it is covered with snow or if the ambient temperature falls below freezing or if the surfaces are in a moist/damp condition. If chemical treatment is to be used, the plan must be approved by the Executive Secretary. Records of water treatment shall be kept for all periods when the plant is in operation. The records shall include the following items:

A. Date
B. Number of treatments made, dilution ratio, and quantity
C. Rainfall received, if any, and approximate amount
D. Time of day treatments were made

Records of treatment shall be made available to the Executive Secretary upon request and shall include a period of two years ending with the date of the request.

Discussion SCC will be required to comply with the most recently EPA approved Fugitive Emissions and Fugitive Dust rule.

7.2 SIP Source Specific Requirements

SCC specific limits and requirements from the 2003 Utah County SIP {UC} are given below. All of the requirements are discussed in bulk after the final requirement.

IX.1.b.E SPRINGVILLE CITY CORPORATION

Requirement - IX.1.b.E.1. A. NO_x emissions from the operation of all engines at the plant shall not exceed 1.68 tons per day. Compliance with the daily mass emission limits shall be demonstrated by multiplying the most recent stack test results by the total hours of operation for each day. Hours of operation shall be determined by supervisor monitoring and maintaining of an operations log. The Utah County SIP [UC] did not have a daily limit and so a comparison of that limit to this SIP can't be made.

Requirement - IX.1.b.E.1.B. NO_x emissions from the operation of all engines at the plant shall not exceed 248 tons per year. Compliance with the annual mass emission limit shall be demonstrated by multiplying the most recent stack test for each engine by the total hours of operation for the rolling 12-month period. Hours of operation shall be determined by supervisor monitoring and maintaining of an operations log. This is the same limit that is in the Utah County SIP[uc].

Requirement - IX.1.b.E.2. Stack testing to show compliance with the emission limitations stated in the above condition shall be performed every three (3) years.

Discussion This limit 1.B is no longer warranted in the PM_{10} SIP; a 24-hour NAAQS now applies. This annual requirement will be removed from with the updated SIP

Additional changes to the requirement relate to the monitoring requirements. The stack testing requirement, IX.1.b.E.2, has been updated with the removal of stack testing and the addition of CEM systems.

7.3 New Maintenance Plan – General Requirements

General requirements have been updated from the Utah County SIP {UC} and are included in the following discussion. The updated general requirements for all listed sources are found in SIP Subsection IX.H.1. This serves as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference.

Conditions 1.a, 1.b and 1.d are declaratory statements and define the framework of the other SIP conditions. They have little in the way of compliance provisions. Condition 1.c is the primary recordkeeping requirement and is further discussed in section 4.2. Conditions 1.e and 1.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

Requirement This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements that the source specific requirements take precedence.

Discussion This paragraph states that the terms and conditions of Subsection IX.H.1 apply to all sources subsequently addressed in the following subsections IX.H.2 and IX.H.3. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

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

Discussion This requirement states that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.1, IX.H.2 and IX.H.3.

Requirement IX.H.1.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.

Discussion This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum

period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions.

Requirement IX.H.1.d All emission limitations listed in Subsections IX.H.2 and IX.H.3 apply at all times, unless otherwise specified in the source specific conditions listed in IX.H.2 and 3.

Discussion This requirement states that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.2 or IX.H.3.

Requirement IX.H.1.e Stack Testing:

i. As applicable, stack testing to show compliance with the emission limitations for the sources in Subsection IX.H.2 and 3 shall be performed in accordance with the following:

A. Sample Location: The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other EPA-approved methods acceptable to the Director.

B. Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2 or other EPA-approved testing methods acceptable to the Director.

C. PM_{10}: 40 CFR 51, Appendix M, Methods 201a and 202, or other EPA approved testing methods acceptable to the Director. If a method other than 201a is used, the portion of the front half of the catch considered PM_{10} shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.

D. SO_2: 40 CFR 60 Appendix A, Method 6C or other EPA-approved testing methods acceptable to the Director.

E. NO_x: 40 CFR 60 Appendix A, Method 7E or other EPA-approved testing methods acceptable to the Director.

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

G. A stack test protocol shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by

the Director. The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, and Occupational Safety and Health Administration (OSHA) approvable access shall be provided to the test location.

H. The production rate during all compliance testing shall be no less than 90% of the maximum production rate achieved in the previous three (3) years. If the desired production rate is not achieved at the time of the test, the maximum production rate shall be 110% of the tested achieved rate, but not more than the maximum allowable production rate. This new allowable maximum production rate shall remain in effect until successfully tested at a higher rate. The owner/operator shall request a higher production rate when necessary. Testing at no less than 90% of the higher rate shall be conducted. A new maximum production rate (110% of the new rate) will then be allowed if the test is successful. This process may be repeated until the maximum allowable production rate is achieved.

Discussion This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species (PM_{10}, NO_x, or SO_2). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

These stack testing requirements supersede those found in IX.H.1.a.A$^{\{OS\}}$ and IX.H.2.a.A$^{\{OS\}}$ of the original SIP.

Requirement IX.H.1.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.

ii. Opacity observations of emissions from stationary sources shall be

conducted in accordance with 40 CFR 60, Appendix A, Method 9.

Discussion This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

These requirements specifically supersede those found in IX.H.1.a.C$^{\{OS\}}$ and IX.H.2.a.C$^{\{OS\}}$ of the original SIP. The original SIP requirements of IX.H.1.a.B$^{\{OS\}}$ and IX.H.2.a.B$^{\{OS\}}$, both of which addressed individual equipment opacity, will be superseded as necessary by the particular source specific limitations found in IX.H.2 or IX.H.3.

7.4 New Maintenance Plan – SCC Specific Requirements

The SCC specific conditions in Section IX.H.3 address those limitations and requirements that apply only to SCC.

IX.H.3.g. Springville City Corporation: Whitehead Power Plant

i. NO_x emissions from the operation of all engines at the plant shall not exceed 1.68 tons per day.

ii. Internal combustion engine emissions shall be calculated from the operating data recorded by the CEM. CEM will be performed in accordance with IX.H.1.f. A day is equivalent to the time period from midnight to the following midnight. Emissions shall be calculated for NO_x for each individual engine by the following equation:

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

Where:

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

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

D = daily output of pollutant in lbs/day

Discussion
SCC is limited to 1.68 tons per day of NO_x emissions with monitoring through CEM. The condition also includes the definition of a day as being from midnight until the following midnight. Compliance shall be determined daily with the use of CEM data and generator output. The equations to be used for the emission calculations are also included.

8.0 Monitoring, Recordkeeping and Reporting

Monitoring requirements are found in the general requirement IX.H.1.e and all common recordkeeping and reporting provisions have been consolidated in the general requirements under IX.H.1.c.

Monitoring of the NO_x emission limit, IX.H.3.g.i, is determined by maintaining daily records of emissions. The emissions are determined from data gathered from the engine's CEM and the power generated by that engine.

9.0 Discussion of Attainment Demonstration

The general requirements act as a framework upon which the other requirements can build. Second, they demonstrate a prevention of backsliding. Through the use of general requirements that are either the same as or functionally equivalent to those in the 2003 Utah County SIP backsliding has been prevented. Finally, when a general requirement has been removed, careful consideration was given as to its specific need, and whether its retention would in any way aid in the demonstration of attainment with the 24-hr standard. If no argument could be made in that regard, the requirement was simply removed.

The source specific limits are equivalent to or more stringent than the requirements from the 2003 Utah County SIP. Requirements that were removed included the yearly NO_x emission limits, as there is no yearly standard. Monitoring, recordkeeping, and reporting requirements were updated with the addition of CEMs and removal of the stack test.

10.0 Implementation Schedule

The requirements imposed on the SCC are effective immediately. SCC did not have any required RACT modifications to undertake from the $PM_{2.5}$ SIP RACT requirements. The emission limits listed in IX.H.3.g can be applied immediately. Similarly, the general requirements, IX.H.1.a-f, can also be applied immediately.

11.0 Emission Limits

Annual and daily emissions are given below.

Table 4: Yearly Emissions and Daily Emission Limits

`	NO_x
Annual	248.00{uc}
Daily (24-hr)	1.68

8.0 Reference

Evaluation Report –

UTAH PM_{10} SIP/MAINTENANCE PLAN

Utah County Nonattainment Area

Supporting Information