State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-031-18a

UTAH AIR QUALITY BOARD MEETING
FINAL AGENDA

Wednesday, June 6, 2018 - 1:30 p.m.
195 North 1950 West, Room 1015
Salt Lake City, Utah 84116

I. Call-to-Order

II. Date of the Next Air Quality Board Meetings: June 19, 2018 and August 1, 2018

III. Approval of the Minutes for May 2, 2018, Board Meeting.

IV. Final Adoption: Change in Proposed Rule R307-403. Permits: New and Modified Sources in Nonattainment Areas and Maintenance Areas. Presented by Thomas Gunter.

V. Final Adoption: Change in Proposed Rule R307-101-2. Definitions. Presented by Thomas Gunter.

VI. Final Adoption: Revision to Carbon Monoxide Maintenance Plan, Provo Area, State Implementation Plan, Section IX, Part C. Presented by Thomas Gunter.

VII. Final Adoption: Amend R307-110-12. Section IX, Control Measures for Area and Point Sources, Part C, Carbon Monoxide. Presented by Thomas Gunter.

VIII. Propose For Public Comment: Revisions to Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits. Presented by Bill Reiss.

IX. Propose For Public Comment: Amend R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits. Presented by Thomas Gunter.

X. Informational Items.
   A. Air Toxics. Presented by Robert Ford.
   B. Compliance. Presented by Jay Morris and Harold Burge.
   C. Monitoring. Presented by Bo Call.
   D. Other Items to be Brought Before the Board.
   E. Board Meeting Follow-up Items.

In compliance with the Americans with Disabilities Act, individuals with special needs (including auxiliary communicative aids and services) should contact Larene Wyss, Office of Human Resources at (801) 536-4281, TDD (801) 536-4284 or by email at lwyss@utah.gov.

ITEM 3

State of Utah

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UTAH AIR QUALITY BOARD MEETING
May 2, 2018 – 1:30 p.m.
195 North 1950 West, Room 1015
Salt Lake City, Utah 84116

DRAFT MINUTES

I. Call-to-Order

Michael Smith called the meeting to order at 1:30 p.m.

Board members present: Michael Smith, Kevin Cromar, Mitra Kashanchi, Cassady Kristensen, Alan Matheson, Arnold Reitze, and William Stringer

Excused: Erin Mendenhall and Randal Martin

Executive Secretary: Bryce Bird

II. Date of the Next Air Quality Board Meeting: June 6, 2018

The next meeting will be on June 6, 2018. There will not be a Board meeting in July. Board members should also plan for a combined lunch meeting with the Legislative Air Quality Policy Advisory Board in mid or late June 2018.

III. Approval of the Minutes for March 7, 2018, Board Meeting.

- Arnold Reitze moved to approve the minutes as submitted. Mitra Kashanchi seconded. The Board approved unanimously.

IV. Final Adoption: R307-101-3. Version of Code of Federal Regulations Incorporated by Reference; R307-210. Standards of Performance for New Stationary Sources; and R307-214. National Emission Standards for Hazardous Air Pollutants. Presented by Thomas Gunter.

Thomas Gunter, Rules Coordinator at DAQ, stated that on January 3, 2018, DAQ presented amendments to these rules to the Board for public comment. These rules must be updated periodically to reflect changes to the federal air quality regulations as published in Title 40 of the Code of Federal Regulations (40 CFR). All published changes to 40 CFR that are relevant to the Utah air quality rules from July 1, 2016, to July 1, 2017, have been summarized in the Board packet. The rules have been amended to identify the most recent version of 40 CFR July 1, 2017,

as the version that is referenced in the Utah air quality rules. A 30-day public comment period was held from February 1 through March 5, 2018, and no comments were received. Staff recommends that the Board adopt R307-101-3, R307-210, and R307-214 as amended.

- Kevin Cromar moved that the Board adopt R307-101-3, R307-210, and R307-214 as amended. Arnold Reitze seconded. The Board approved unanimously.

V. Informational Items.

A. PM2.5 State Implementation Plan Update. Presented by Bill Reiss.

Bill Reiss, Environmental Scientist at DAQ, updated that the Provo and Salt Lake areas are classified as serious nonattainment areas. The Cache Valley is classified as moderate. The monitoring data for the Provo nonattainment area has shown that over the last four years we have been attaining the standard. The new PM implementation rule incorporates EPA's long standing Clean Data Areas Policy whereby a nonattainment area (NAA) that has data showing attainment of the health standard may have its obligation to submit certain SIP elements suspended. The obligation would remain suspended unless the area is re-designated to attainment or the EPA determines that the area has re-violated the standard. The requirements that would be suspended include a modeled attainment demonstration, reasonable further progress plan, contingency measures, and milestone identification.

A Clean Data Determination does not however suspend all of the elements typically required in a SIP. EPA has identified other elements that independently help the area improve air quality. States would still be required to complete and submit a base year emissions inventory, provisions to implement serious area best available control measures (BACM) / best available control technology (BACT), and nonattainment new source review provisions for PM2.5 to the EPA. DAQ and EPA compared this option with actually completing the whole state implementation plan (SIP) and decided that this is the best course of action. Utah would still get the SIP elements that lead to improvements in air quality but would avoid potential penalties in the Clean Air Act (CAA) should we get another year like 2013. Staff is also mindful of EPA's completeness deadline of June 30, 2018, and believes that DAQ can give EPA what they need in time to meet that date. Mr. Reiss then addressed questions from the Board in regards to the Provo area.

Mr. Reiss was asked to clarify the considerations staff is working through and does that include differences in actual control measures, to which he replied that no, there is no difference in the control measures just because a Clean Data Determination will suspend other elements of what would be an entire SIP. These are the same control measures that we would have included in a SIP that also included a modeled evaluation of the situation. But as it is with the clean data we're looking at, we could have packaged together a SIP that had as its starting point a level below the NAAQS already. So it would be an exercise in the obvious really. And that SIP would have included this same package of controls. For Utah County, regardless of which path taken, there will not be any differences in the control measures the Board will be asked to consider.

The Salt Lake area SIP is more complicated. Similar to the Provo area, the Salt Lake area air quality monitoring data shows improvement, but unfortunately it is not good enough that DAQ can employ the same path forward as in Provo. DAQ will still need to produce a SIP for the Salt Lake area. This will enable DAQ to use the last three years of data which will represent a more favorable starting design value. From that starting design value DAQ

will then assess improvements in emissions through the model and hopefully achieve the standard when the model is complete. In addition, DAQ still needs to move the base year emissions inventory to coincide with the more recent period of air quality data which will take a couple of weeks before the model can run again. If all goes as expected, a SIP package could be assembled in the coming months. In the near-term however, the provisions to ensure BACT/BACM will be available and posted as they are completed. Unlike the Provo area, some of the analysis has shown that a few modifications to the SIP limits in the Salt Lake area Part H are needed. The Part H modifications will be coming to the Board at the June meeting and through the administrative process will start public review on July 1, 2018. Mr. Reiss then addressed questions from the Board.

In response to the question of is the data is showing improvement every year or is it just plateauing, staff responded that they look at the emissions coming from the footprint we have on the valley floor, which can be measured in terms of tonnage per year, and a number of precursors as well as just $PM_{2.5}$. The other way to look at emissions is with our air quality monitors. Both of these show a downward trend.

The Subpart H limits are not the only parts needed to complete the SIP packages, BACT reports, which are independent of the demonstration of attainment, will need to be available for inspection by the time the public comment period begins.

The best time to revise or review existing rules that are part of the SIP is when the rules are sent out for public comment. There is also an opportunity when EPA does its review on what was submitted to their office.

B. PM2.5 State Implementation Plan. Presented by Joro Walker, Western Resource Advocates.

Joro Walker, of Western Resource Advocates, and Jessica Reimer, of HEAL Utah, gave a presentation on BACM and the serious SIP as related to the Provo and Salt Lake NAAs. EPA's implementation rule requires adoption of BACT and BACM, and if those are not going to be accepted then a detailed justification is required. A serious nonattainment designation requires that BACT/BACM includes any quality measure that can be fully/partially implemented by 2019. If a measure is implemented in other NAAs without unreasonable economic impacts, it should be economically feasible. BACT is independent of attainment and applies year-round.

For wood burning, it is suggested that a lower burn ban threshold be adopted permanently and also include public education and outreach programs. Under Utah's serious SIP proposal there is a threshold at which voluntary and mandatory action days are called. There is a discrepancy with the moderate SIP contingency measure of 15 $\mu g/m^1$ and the proposed 25 $\mu g/m^1$ under the serious SIP. They are suggesting that a lower threshold of either 20 or 15 $\mu g/m^1$ is reasonable. Salt Lake County already bans wood burning on voluntary and mandatory action days.

DAQ indicates that Utah's current fugitive dust rule is part of the serious SIP and does not need to be changed. Other states require lower and stricter requirements, and so under BACM those sorts of measures are appropriate for consideration in Utah's SIP.

Mobile sources are a significant source of our PM2.5 problem. They suggest that California's BACM be considered and adopted as BACM in Utah. Any state may adopt

California on-road vehicle standards and several states have. Adopting the clean car program is the only way Utah will be able to keep the criteria pollution reduction benefits of the federal standards if repealed.

The off-road and non-road mobile source is an important category in Utah because so many sources are in the NAA. One difficulty about this category is that we don't have a good inventory of these sources. All the projections in the SIP come from population estimates. They feel that adopting stricter regulations would be an improvement. California has specific waivers in place that EPA has approved and other states are allowed to adopt, such as the in-use off-road diesel-fueled fleets regulations. In addition, states and cities have adopted public contracting requirements to reduce diesel emission from construction activities.

Finally, Utah was required to have an operational PM2.5 near-road monitor by January 1, 2017, and does not. Scientific evidence indicates that emissions of PM2.5 are higher near highways. Without an operational monitor, Utah cannot show attainment and cannot ensure communities near highways are protected from high levels of PM2.5.

In closing, they suggest the next steps are to either reject a SIP that fails to consider and adopt BACM, or adopt a SIP and establish a process that requires consideration and adoption of BACM. Staff was then asked to respond to questions from the Board about specific points made in the presentation.

In response to what has been done in terms of non-road mobile in terms of BACM analysis, Mr. Reiss explained that non-road emissions are assessed through EPA's non-road model. That model allows you to predict forward into time and has built into it a lot of controls of non-road engines that are done at the federal level. This is essentially EPA's jurisdiction under Title 2 of the CAA to control the non-stationary sources. When DAQ does its assessment of emissions at various points in time the model gives output for each of those points, which presumably includes all the federal measures.

As to whether staff has reviewed California standards for BACM, Glade Sowards of DAQ, responded that staff has looked at California standards over the years for both non-road and on-road. Non-road analysis is more complicated because there are so many different categories of non-road equipment and also because of the limitations of our inventory. As was pointed out, we do have several federal standards that have been in place over the years.

Staff agreed with the comment that there is nothing that stops Utah from adopting in-use regulations for vehicles once they are in consumer hands and in fact staff is beginning down that path but it is very resource intensive. Mr. Cromar stated his disagreement with DAQ's judgment call for priorities and that it would be worth considering and prioritizing the non-road sources.

C. Records Stakeholder Meeting Update. Presented by Rusty Ruby.

Rusty Ruby, Compliance Branch Manager at DAQ, stated that a records stakeholder meeting was held on April 9, 2018, which included staff, environmental advocates, the Association of General Contractors, the Manufacturer Association, the Mining Association, and the Petroleum Association. Staff presented an overview of its records program and also an explanation of EPA's records process with the federal standards. The

Attorney General's Office gave a summary of the state's Government Records Access and Management Act. At the conclusion, the Association of General Contractors' environmental committee offered to host a future meeting of their records and how they submit records to the state.

D. Air Toxics. Presented by Robert Ford.

E. Compliance. Presented by Jay Morris and Harold Burge.

F. Monitoring. Presented by Kevin Hart.

G. Other Items to be Brought Before the Board.

Mr. Bird stated that EPA announced designated areas nationwide that are not in compliance with the 2015 revised 8-hour standard for ozone pollution. In Utah, the areas designated as marginal nonattainment for the Wasatch Front included all or parts of Salt Lake, Davis, Weber, Tooele, and Utah counties. Areas affected in the Uinta Basin include parts of Uintah and Duchesne counties below an elevation of 6,250 feet. The EPA also designated Tribal lands in the Uinta Basin. Under the marginal nonattainment designation Utah is not required to submit a formal SIP. However, the state is required to meet the standard of 70 ppb within the next three years.

Mark Berger, Air Quality Policy Section Manager at DAQ, announced that EPA awarded Utah approximately $12.7 million through its targeted air shed grants for projects in Salt Lake City, Logan, and Provo nonattainment areas. Approximately $3.1 million will be used in Logan to replace old diesel trucks; and approximately $3.1 in each area of Logan, Provo, and Salt Lake City for wood-burning appliance change-out projects. The DAQ will start identifying projects and has five years to use the funds.

Staff responded to Mr. Cromar's inquiry if there are any correspondences to EPA that the Board has been involved with or should be involved with. In the past, the Board has submitted its comments to EPA separate from DAQ/DEQ comments, but it is not an official role or statutory duty of the Board.

H. Board Meeting Follow-up Items.

- The Utah Air Quality Board and the Legislative Air Quality Policy Advisory Committee will hold a combined lunch meeting sometime in mid to late June.

Meeting adjourned at 2:38 p.m.

ITEM 4

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DAQ-036-18

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Bill Reiss, Environmental Engineer

DATE: May 24, 2018

SUBJECT: FINAL ADOPTION: Change in Proposed Rule R307-403. Permits: New and Modified Sources in Nonattainment Areas and Maintenance Areas.

EPA determined that there were potential deficiencies in Utah's nonattainment new source review (NNSR) permitting rules. In response, the Division of Air Quality sent a letter to EPA committing to revise portions of R307-403 no later than December 8, 2017.

Amendments to R307-403 attempting to fulfill the commitments made to the EPA were proposed in September 2017, but on December 6, 2017, the Board voted to let the proposed amendment lapse, raising concerns over the exclusion of ammonia as a precursor pollutant. As a result, the Division of Air Quality is now in breach of the commitment letter.

EPA has indicated that it would issue a Finding of Failure to Submit within six to eight months from the December 8, 2017, deadline. Such finding would put Utah on notice that if it failed to rectify the commitments made in the letter, EPA would be forced to apply sanctions, including mandatory offset regulations and/or loss of federal highway funding.

On March 7, 2018, the Division of Air Quality re-addressed R307-403, attempting to satisfy the ammonia precursor issues raised in the December 2017 Board meeting, and still conform to the commitments made in the letter to EPA. In a revised version of R307-403, the Board proposed exempting ammonia as a PM2.5 precursor only in the Logan nonattainment area, where a demonstration supporting that conclusion has been submitted to EPA. In the Salt Lake and Provo nonattainment areas, where any such conclusion has yet to be demonstrated, ammonia remains a PM2.5 precursor as per the federal rules in 40 CFR 51.165. The Board proposed these amendments for a 30-day public comment period.

A public comment period was held from April 1 to April 30, 2018. No hearing was requested. Staff received multiple written comments on this proposal that are summarized below.

Recommendation: Staff recommends that the Board adopt the change in proposed rule R307-403, Permits: New and Modified Sources in Nonattainment Areas and Maintenance Areas.

Response to Comments

EPA Region 8 Comments

Comment #1 – EPA Region 8. Regarding R307-403-1. Purpose and Definitions; Revisions to the Definition of "Significant"

The revisions to R307-403-1(4)(b) state:

The following subparagraphs specify, for certain nonattainment areas, emissions rates that are "significant" for ammonia: (1) In the Provo, UT nonattainment area (as defined in the July 1, 2017 version of 40 CFR 81.345) -70 tons per year or more (2) In the Salt Lake City, UT nonattainment area (as defined in the July 1, 2017 version of 40 CFR 81.345) - 70 tons per year or more.

In the EPA's August 24, 2016 final rulemaking "Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements; Final Rule" (81 FR 58010) ("$PM_{2.5}$ Implementation Rule"), we did not promulgate a significant emissions rate (SER) for ammonia. Instead, the Rule finalized a provision that requires states that must regulate modified major stationary sources of ammonia in nonattainment areas to develop and submit a definition of "significant," such as an appropriate SER for ammonia. We recommended that states consult with the appropriate EPA Regional Office to develop an ammonia SER as a means of defining "significant" for a particular nonattainment area. The $PM_{2.5}$ Implementation Rule also recommended that states that regulate ammonia as a $PM_{2.5}$ precursor should develop a technical justification for the ammonia SER for a nonattainment area and include this justification as part of their nonattainment SIP rules submission to the EPA for approval. We note that UDAQ's revisions to R307-403-1(4)(b) did not include such a technical justification, and therefore, we recommend that UDAQ develop a technical justification with the $PM_{2.5}$ Implementation Rule.

DAQ Response: DAQ agrees that the significant emission rates established in R307-403-1, for the Provo, UT and Salt Lake City, UT nonattainment areas, should have a technical basis. Although air quality modeling has not been completed or submitted as part of a Serious Area SIP for either of these areas, DAQ has, in consultation with EPA Region 8, used the CAMx model as developed for this SIP work to assess what would be an appropriate emission rate to establish as significant.

A summary of this analysis, which encompasses both nonattainment areas, is currently available for inspection on line at the DAQ website (https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2018-004852.pdf). It supports the establishment of 70 tons per year (tpy) as the Significant Emissions Rate (SER) for ammonia in each area. Some additional context is added here:

This modeling was first performed using EPA's "Draft $PM_{2.5}$ Precursor Demonstration Guidance" (Nov. 17, 2016) to determine whether it would be appropriate to exempt, from Nonattainment New Source Review, what would be a new major source of ammonia. Results were not definitive enough to support a petition to exclude ammonia from Nonattainment New Source Review (NNSR); nor in related analyses, to exclude ammonia from consideration when reviewing existing sources from BACM/BACT review within the context of a Serious Area nonattainment SIP. It might be said that the one definitive conclusion one might draw regarding ammonia is that additional work to better understand its origins, its ambient concentrations, and its depiction in the air quality model will be necessary in the coming years.

In recent rulemaking, EPA expanded its enumeration of Significant Emission Rates for $PM_{2.5}$ precursors. A SER for VOC was set at 40 tpy, the same number already affixed to NOx and SO_2 for purposes of the $PM_{2.5}$ NSR program. EPA had given some consideration, in the development of the

2008 $PM_{2.5}$ NSR Rule, to setting SERs for the individual $PM_{2.5}$ precursors at different levels, but concluded that it did not have adequate data on the impacts of precursor emissions from individual sources to override the administrative advantages of setting the SERs for purposes of the $PM_{2.5}$ NSR program at the same levels that are already used for other purposes in the major NSR program for other NAAQS (FR 80, 15340).

Within the federal definition of "major stationary source" is a clause that includes "Any physical change that would occur at a stationary source not qualifying under paragraphs (a)(1)(iv)(A)(1) or (2) of this section as a major stationary source, if the change would constitute a major stationary source by itself." The emissions threshold for a major stationary source in a Serious $PM_{2.5}$ nonattainment area is 70 tpy for $PM_{2.5}$ or any individual $PM_{2.5}$ precursor. Thus, if any existing source were to propose an increase of 70 tpy of ammonia, it would be regarded as a major stationary source and would therefore become subject to the review requirements of NNSR. For this reason, 70 tpy may be regarded as a "ceiling" for the establishment of a SER. And, since 40 tpy has been established as the SER for each of the other $PM_{2.5}$ precursors, 40 tpy may therefore be regarded as a "floor."

Given the uncertainties surrounding the modeled analysis of ammonia's contribution to ambient $PM_{2.5}$ concentrations, it would seem ambitious to use that model to more precisely define, for purposes of $PM_{2.5}$ NSR, an emission rate somewhere between 40 tpy and 70 tpy. This is especially so given the total lack of guidance from EPA regarding the performance of such an analysis. We note that the existing guidance surrounding the analysis of precursor emissions is still in draft form, and furthermore it is silent on the establishment of a SER for ammonia.

Undoubtedly some may ask for refinements in the modeled analyses. However, it is worth noting that in this instance one might reach the same conclusion EPA did in 2008 when faced with a shortage of adequate data to analyze. It noted the administrative advantage of moving forward with rulemaking for $PM_{2.5}$ NSR while reserving the right to re-visit the question at a later point in time.

Comment #2 – EPA Region 8. Regarding R307-403-1. Purpose and Definitions; Revisions to the Definition of "regulated NSR pollutant"

The revisions to R307-403-1(4)(c) add paragraph (c)(2), which states:

Except as specified in R307-101-2 and where a demonstration satisfying 40 CFR 51.1006(a)(3) has, for a particular $PM_{2.5}$ nonattainment area, determined otherwise; sulfur dioxide, nitrogen oxides, volatile organic compounds and ammonia are precursors to $PM_{2.5}$ in any $PM_{2.5}$ nonattainment area.

We recommend that this paragraph clearly specify that a demonstration that a $PM_{2.5}$ precursor is not significant for NNSR purposes must be approved by the EPA, and we offer the following suggested revision to paragraph (c)(2):

Except as specified in R307-101-2 and where <u>the Administrator of the EPA has approved</u> a demonstration satisfying 40 CFR 51.1006(a)(3) <u>which</u> has, for a particular $PM_{2.5}$ nonattainment area, determined otherwise; sulfur dioxide, nitrogen oxides, volatile organic compounds and ammonia are precursors to $PM_{2.5}$ in any $PM_{2.5}$ nonattainment area.

DAQ Response: DAQ agrees, and will make the recommended clarification.

Comment #3 – EPA Region 8. Regarding R307-403-4. Offsets: General Requirements

The EPA recommends adding the statement "Emission offsets must be surplus, permanent, quantifiable, and federally enforceable," as indicated in 40 CFR part 51, Appendix S, to R307-403-4 (Offsets: General Requirements). In particular, 40 CFR 51.165(a)(3)(ii)(C)(i) requires an approved NNSR program to provide that emission reductions from shutdowns or curtailments must be surplus, permanent, quantifiable, and federally enforceable to be creditable as offsets.

DAQ Response: DAQ agrees, and will make the recommended clarification in paragraph 403-4 (4).

Rio Tinto Kennecott Comments

Comment #4 – Rio Tinto Kennecott. Regarding R307-403-5. Offsets: Particulate Matter Nonattainment Areas

R307-403-5 (1) outlines offsetting requirements for new and modified sources in the PM_{10} non-attainment area. Offsetting ratios are listed for emissions increases greater than 50 tons per year (tpy) and for emissions increases between 25 tpy and 50 tpy. The proposed rule states that for offsets determination, PM_{10}, sulfur dioxide, and nitrogen oxide shall be considered on an equal basis. The rule as proposed does not provide clarity on the offsetting requirements between major sources/major modifications and minor sources/minor modifications.

RTKC is requesting clarifications to the proposed rule identifying specific offsetting requirements for both major and minor sources, and major and minor modifications to existing sources.

DAQ Response: DAQ agrees, and has revised the proposed rule in several locations to make this distinction. As proposed, paragraph (5)(1) only addressed Utah-specific PM_{10} offsetting requirements that were written into the SIPs for Salt Lake and Utah counties. These State-only requirements are separate from the federal Nonattainment New Source Review (NNSR) requirements incorporated throughout R307-403, and more specifically from the general NNSR offsetting requirements addressed in R307-403-(4).

The following revisions are intended to clarify what is required in PM_{10} nonattainment areas.

Most significantly, the very beginning of the paragraph R307-403-5 (1) is now denoted as subparagraph (a). It now reads:

(a) In addition to the general offsetting requirements of R307-403-4, as they apply to new major sources and major modifications as defined in R307-403-2(10)(b), new sources which have a potential to emit, or modified sources which would produce an emission increase equal to or exceeding the tonnage total of combined PM_{10}, sulfur dioxide, and oxides of nitrogen listed below which are located in or impact a PM_{10} Nonattainment Area as defined in R307-403-5(1)(e), shall obtain an enforceable offset as defined in R307-403-5(1)(b) and R307-403-5(1)(c).

…where subparagraphs 5(1)(b) and 5(1)(c) identify the tonnage thresholds and associated offset ratios required by the Utah-specific offset conditions.

The statement: "**In addition to the general offsetting requirements of R307-403-4, as they apply to new major sources and major modifications as defined in R307-403-2(10)(b)** is intended to indicate that both sets of requirements must be satisfied in order to secure a permit.

The general offsetting requirements of R307-403-4 apply only to new major sources and major modifications, and stipulate that "the total tonnage of increased emissions of the air pollutant from the new or modified source shall be offset by an equal or greater reduction, as applicable, in the actual emissions of such air pollutant". Thus, the offset ratio is at least 1 to 1, and offset required for one pollutant may not be satisfied with emission credits belonging to another. In other words, there is to be no inter-pollutant trading.

By contrast, the Utah-specific rule uses PM_{10}, SO_2, and NOx interchangeably, for both the assessment of applicability and the satisfaction of offsets required. Offsets may be required at a ratio of 1 to 1, or at a ratio of 1.2 to 1. This requirement may apply to sources or modifications that are not "major" as defined in R307-403-2(10)(b), and are for that reason sometimes called the "minor source offset requirements."

Two other revisions to R307-403 were made to further underscore the distinction described above. These are as follows:

Paragraph 403-1. Purpose and Definitions; Paragraph (1) This paragraph indicates that R307-403 implements the federal nonattainment NSR provisions of 40 CFR 51.165, but that it also contains some NSR provisions for non-major sources in PM_{10} nonattainment areas. A reference to R307-403-5 (1) has been inserted to specifically identify these non-major source provisions.

Paragraph 403-4. Offsets: General Requirements; Paragraph (3) The following statement was added to the end of this paragraph: **Offsets may not be traded between pollutants, except as required only to satisfy R307-403-5(1) where it pertains to emission increases that are not considered major for PM_{10} or a PM_{10} precursor.**

Comment #5 – Rio Tinto Kennecott. Regarding R307-403-5. Offsets: Particulate Matter Nonattainment Areas

R307-403-5 (2) outlines offsetting requirements for major sources and major modifications in the $PM_{2.5}$ non-attainment area. Offsets are required for significant emissions increases or net significant emissions increases of $PM_{2.5}$ and/or precursors. The proposed rule does not provide clarity on the offsetting ratios for primary $PM_{2.5}$ and precursors.

RTKC is requesting clarification on the proposed rule to include specific offsetting requirements for primary $PM_{2.5}$ and precursors.

DAQ Response: DAQ agrees. The following revisions are intended to clarify what offset ratios are required in $PM_{2.5}$ nonattainment areas.

Paragraph 403-5. Offsets: Particulate Matter Nonattainment Areas; Paragraph (2)

New subparagraph R307-403-5(2)(a) begins with the same reminder (as for PM_{10}) that the general offset requirements of R307-403-4 apply in addition to what appears below. Again, the general offsetting requirements of R307-403-4 stipulate that "the total tonnage of increased emissions of the air pollutant from the new or modified source shall be offset by an equal or greater reduction, as applicable, in the actual emissions of such air pollutant". Thus, the offset ratio is at least 1 to 1, and there is to be no inter-pollutant trading.

R307-403-5(2)(a) then requires that enforceable offset shall be obtained as defined in R307-403-5 (2)(d) through (2)(f).

Renumbered subparagraph R307-403-5(2)(d) explains that emissions shall be offset at a ratio of no less than 1-to-1. Clarification has been added to explain that "**If the quantity of offsets is determined to be a non-whole number**, the offset required shall be rounded up to the next whole number."

Renumbered subparagraph R307-403-5(2)(e) entertains the idea that some $PM_{2.5}$ areas may also be designated nonattainment for PM_{10} and/or ozone, and that certain precursors to $PM_{2.5}$ may also be precursors to PM_{10} and/or ozone. Increases in the emissions of these precursors could be subject to more than one offset ratio. In such instances, subparagraph R307-403-5(2)(e) requires that the most stringent offset ratio would apply in order to satisfy each of the respective conditions. A reference to R307-420 (Permits: Ozone Offset Requirements in Davis and Salt Lake Counties) was inserted and the wording was changed to clarify that the offset requirements would need to be triggered for these other pollutants before this condition would apply.

[See also Comment #11 below.]

<u>Clarifications Suggested by Division of Air Quality:</u>

Comment #6 – Division of Air Quality. General clarifications throughout R307-403

6.a. 403-2. Applicability; Paragraph (1)(b) Specificity was added to the citation in this paragraph that points the reader to the various calculation tests presented later in the rule.

6.b. 403-2. Applicability; Paragraph (5)(a) The word "*provision*" was changed to "*provision<u>s</u>*".

6.c. 403-2. Applicability; Paragraph (6)(d) Clarification was added to the reporting requirements, to specify that it is each *calendar* year that records are to be generated.

6.d. 403-3. Review of Major Sources of Air Quality Impact; Paragraph (3) To clarify that the terms of this paragraph apply also to major stationary sources and major modifications of precursor emissions, the phrase "*or any individual precursor to that pollutant*" was inserted into the proposed language.

6.e. 403-4. Offsets: General Requirements; Paragraph (1) The phrase "*or any individual precursor to the pollutant*" was inserted to clarify that these requirements would apply to precursors in addition to "the pollutant for which the area is designated nonattainment."

6.f. 403-5. Offsets: Particulate Matter Nonattainment Areas; Paragraph (1) Paragraph (1) addresses offset requirements within PM_{10} nonattainment areas, and several clarifications were made within.

Most significantly the very beginning of the paragraph is now denoted as subparagraph (a), and inserted at the start is the following statement: "*In addition to the general offsetting requirements of R307-403-4, as they apply to new major sources and major modifications as defined in R307-403-2(10)(b).*" See also Comment# 5.

What had been denoted as subparagraph (a), identifying the maximum allowable impact on a PM_{10} nonattainment area from sources proposing to locate outside the area, is now moved to subparagraph (e) and re-referenced above.

Subparagraph (b) is clarified by inserting the phrase "*established at a ratio*" at two locations.

The second sentence of subparagraph (b) is re-phrased to accommodate the addition of NOx offsetting requirements related to $PM_{2.5}$.

Comment #7 – Division of Air Quality. 403-2. Applicability; Paragraph (10)

The review of new major sources and major modifications in nonattainment, as articulated in R307-403, is broader in scope than just the offsetting requirements. R307-403-2(10) intends to say that all of these requirements will apply to the respective precursor emissions, in the respective nonattainment areas, for ozone, $PM_{10,}$ and $PM_{2.5}$. Instead, the rule revision proposed on March 7th had specified that these applicability provisions were "for offsetting requirements." Such language may have implied that other NNSR requirements, such as LAER, alternative siting requirements, etc., would not have applied to the precursor emissions.

> DAQ Response: To correct this, the phrase "**for offsetting requirements**" has been stricken. Also, the word "**individual**" has been inserted to clarify that precursor emissions are not summed to determine applicability.

Comment #8 – Division of Air Quality. 403-2. Applicability; Paragraph (10)(b)

R307-403-2(10)(b) applies to areas of PM_{10} nonattainment. The proposed language had attempted to indicate that increases in PM_{10} precursor emissions would trigger offset requirements if emitted in quantities sufficient to trigger NNSR. It also intended to clarify that the precursors to PM_{10} include nitrogen oxides and sulfur dioxide. As noted in Comment #8, the NNSR requirements encompass more than just offsetting.

> DAQ Response: To ensure that the requirements of NNSR are to be applied more comprehensively, the proposed language, which had included the phrase "shall trigger offset requirements" has been stricken, and in its place is language that applies "the requirements of R307-403" to potential increases of nitrogen oxides and sulfur dioxide. This language reverts back to the original language for PM_{10} (that had been proposed for deletion at the beginning of paragraph (10)), except that the existing reference to "PM_{10} precursors" now indicates that these precursors are to specifically include nitrogen oxides and sulfur dioxide. Otherwise, it is the same language that is used in 40 CFR 51.165 (a)(10).

Comment #9 – Division of Air Quality. 403-2. Applicability; Paragraph (10)(c)

R307-403-2(10)(c) applies to areas of $PM_{2.5}$ nonattainment. The proposed language had attempted to indicate that increases in $PM_{2.5}$ precursor emissions would trigger offset requirements if emitted in quantities sufficient to trigger NNSR. As noted in Comment #8, the NNSR requirements encompass more than just offsetting.

> DAQ Response: To ensure that the requirements of NNSR are to be applied more comprehensively, the proposed language, which had included the phrase "shall trigger offset requirements" has been stricken, and in its place is language that applies "the requirements of R307-403" to potential increases of any individual $PM_{2.5}$ precursor. This is the same language that is used in 40 CFR 51.165 (a)(13).

Comment #10 – Division of Air Quality. 403-3. Review of Major Sources of Air Quality Impact; Paragraph (3)(e)

R307-403-3(3)(e) lists one of the criteria to be met in order for a major new source or an existing source with a major modification to secure a permit. The criterion in subparagraph (e) had required that "**there is an approved implementation plan in effect for the pollutant to be emitted by the proposed source**." This criterion is more accurately stated by the revised language, which reads: "**the restrictions on new or modified sources identified in 40 CFR 52.24 are not applicable**."

DAQ Response: These restrictions in 40 CFR 52.24 implement a prohibition on construction of new or modifying major sources, that are major for the pollutant (or precursors) for which the area is designated nonattainment under the following circumstances:

- The State failed to submit an implementation plan meeting the requirements of an approvable new source review permitting program, or
- The new source review permitting program is not being adequately implemented for the area in which the proposed source is to be constructed or modified.

Comment #11 – Division of Air Quality. 403-5. Offsets: Particulate Matter Nonattainment Areas; Paragraph (2)

R307-403-5(2) addresses $PM_{2.5}$ nonattainment areas. As revised, it is fundamentally identical to what was initially proposed on March 7th, but it has been re-organized to more easily explain to the reader what is required. The following description follows paragraph 403-5 (2) through its new structure:

R307-403-5(2)(a) begins with the same reminder (as is now inserted into the PM_{10} paragraph) that these requirements apply in addition to the general offsetting requirements of R307-403-4. After that is the general statement that new major sources or major modifications to existing sources are to obtain offsets as defined in the last three subparagraphs of 403-5 (2). All of this language was simply moved forward from what had been paragraph 403-5 (4).

R307-403-5(2)(b) then explains what a major source is: (i) in Moderate $PM_{2.5}$ nonattainment areas, (ii) in Serious $PM_{2.5}$ nonattainment areas, and (iii) in cases where an existing minor source would make a big enough modification.

What had been R307-403-5(2)(d) is now stricken out. This is language that had been proposed as new on March 7th, and also appeared (though specific only to offsetting) in the applicability section 403-2 (10). As discussed in Comment #10, that language is now replaced by language used in the federal rule to convey this meaning (40 CFR 51.165 (a)(13)). In short, there is a better way to say this, and it is now said that way in R307- 403-2 (10).

What had been R307-403-5(4) is then also stricken out. This is the afore-mentioned requirement to obtain offset that has been moved forward to R307-403-5(2)(a).

R307-403-5(2)(c) explains how to determine if a proposed modification would be a major modification. This had been R307-403-5(4)(a).

What had been R307-403-5(4)(b) is now stricken out. This is language had identified the maximum allowable impact on a $PM_{2.5}$ nonattainment area, from sources proposing to locate outside the area.

Although this information is important and relates to the applicability denoted in R307-403-5(2)(a), it already appears (in tabular form) in R307-403-3(1) and need not be repeated here.

R307-403-5(2)(d), (e), and (f) provide the offset criteria that affected sources must meet in addition to the general offset requirements of R307-403-4. They had been labeled (c), (d), and (e). In addition to the re-numbering, clarification has been added to R307-403-5(d) and (e).

R307-403-5(2)(d) explains that emissions shall be offset at a ratio of no less than 1-to-1. Clarification has been added to explain that "**If the quantity of offsets is determined to be a non-whole number**, the offset required shall be rounded up to the next whole number."

R307-403-5(2)(e) entertains the idea that some $PM_{2.5}$ areas may also be designated nonattainment for PM_{10} and/or ozone, and that certain precursors to $PM_{2.5}$ may also be precursors to PM_{10} and/or ozone. Increases in the emissions of these precursors could be subject to more than one offset ratio. In such instances, R307-403-5(2)(e) requires that the most stringent offset ratio would apply in order to satisfy each of the respective conditions. A reference to R307-420 (Permits: Ozone Offset Requirements in Davis and Salt Lake Counties) was inserted and the wording was changed to clarify that the offset requirements would need to be triggered for these other pollutants before this condition would apply.

R307. Environmental Quality, Air Quality.
R307-403. Permits: New and Modified Sources in Nonattainment Areas and Maintenance Areas.
R307-403-1. Purpose and Definitions.

(1) Purpose. This rule implements the federal nonattainment area permitting program for major sources as required by 40 CFR 51.165. In addition, the rule contains new source review provisions for some non-major sources in PM_{10} nonattainment areas. [~~This rule~~]R307-403-5(1), supplements, but does not replace, the permitting requirements of R307-401.

(2) Unless otherwise specified, all references to 40 CFR in R307-403 shall mean the version that is in effect on July 1, 2017.

(3) Except as provided in R307-403-1(4), the definitions in 40 CFR 51.165(a)(1) are hereby incorporated by reference. The definition of PAL, or plant wide applicability limitation, in 40 CFR 51.165(f)(2)(v) is also incorporated by reference.

(4)(a) "Reviewing authority" means the director.

(b) In the definition of "significant" in 40 CFR 51.165(a)(1)(x) add the following text at the end of paragraph (F): "The following subparagraphs specify, for certain nonattainment areas, emission rates that are "significant" for Ammonia: (1) In the Provo, UT nonattainment area (as defined in the July 1, 2017 version of 40 CFR 81.345) - 70 tons per year or more (2) In the Salt Lake City, UT nonattainment area (as defined in the July 1, 2017 version of 40 CFR 81.345) - 70 tons per year or more."

(c) In the definition of "regulated NSR pollutant" in 40 CFR 51.165(a)(1)(xxxvii), paragraph (C)(2)is amended to read: "(*2*) Except as specified in R307-101-2 and where the Administrator of the EPA has approved a demonstration satisfying 40 CFR 51.1006(a)(3) which has, for a particular $PM_{2.5}$ nonattainment area, determined otherwise; Sulfur dioxide, Nitrogen oxides, Volatile organic compounds and Ammonia are precursors to $PM_{2.5}$ in any $PM_{2.5}$ nonattainment area."

(d) The following definitions or portions of definitions that apply to the equipment repair and replacement provisions are not incorporated because these provisions were vacated by the DC Circuit Court of Appeals on March 17, 2006:

(i) in the definition of "major modification" in 40 CFR 51.165(a)(1)(v)(C), the second sentence in subparagraph (1);

(ii) the definition of "process unit" in 40 CFR 51.165(a)(1)(xliii);

(iii) the definition of "functionally equivalent component" in 40 CFR 51.165(a)(1)(xliv);

(iv) the definition of "fixed capital cost" in 40 CFR 51.165(a)(1)(xlv); and

(v) the definition of "total capital investment" in 40 CFR 51.165(a)(1)(xlvi).

R307-403-2. Applicability.

(1) R307-403 applies to any new major stationary source or major modification that is major for the pollutant or precursor pollutant for which the area is designated nonattainment under section 107(d)(1)(A)(i) of the Clean Air Act, if the stationary source or modification would locate anywhere in the designated nonattainment area.

(a) Except as otherwise provided in paragraph R307-403-2(2), and consistent with the definition of major modification contained in 40 CFR 51.165(a)(1)(v)(A), a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases-a significant emissions increase (as defined in 40 CFR 51.165(a)(1)(xxvii)), and a significant net emissions increase (as defined in 40 CFR 51.165(a)(1)(vi) and (x)). The project is not a major modification if it does not cause a significant emissions increase. If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

(b) The procedure for calculating (before beginning actual construction) whether a significant emissions increase (i.e., the first step of the process) will occur depends upon the type of emissions units being modified, according to paragraphs R307-403-2(c)(1) through ([~~e~~]f). The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major stationary source (i.e., the second step of the process) is contained in the definition in 40 CFR 51.165(a)(1)(vi). Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.

(c) Actual-to-projected-actual applicability test for projects that only involve existing emissions units. A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions (as defined in 40 CFR 51.165(a)(1)(xxviii)) and the baseline actual emissions (as defined in 40 CFR 51.165(a)(1)(xxxv)(A) and (B), as applicable), for each existing emissions unit, equals or exceeds the significant amount for that pollutant (as defined in 40 CFR 51.165(a)(1)(x)).

(d) Actual-to-potential test for projects that only involve construction of a new emissions unit(s). A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit (as defined in 40 CFR 51.165(a)(1)(iii)) from each new emissions unit following completion

of the project and the baseline actual emissions (as defined in 40 CFR 51.165(a)(1)(xxxv)(C)) of these units before the project equals or exceeds the significant amount for that pollutant (as defined in 40 CFR 51.165(a)(1)(x)).

(e) Reserved.

(f) Hybrid test for projects that involve multiple types of emissions units. A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the method specified in R307-403-2(1)(c) through (d) as applicable with respect to each emissions unit, for each type of emissions unit equals or exceeds the significant amount for that pollutant (as defined in 40 CFR 51.165(a)(1)(x)).

(2) For any major stationary source for a PAL for a regulated NSR pollutant, the major stationary source shall comply with requirements under R307-403-11.

(3) Reserved.

(4) Reserved.

(5)(a) Approval to construct shall not relieve any owner or operator of the responsibility to comply fully with applicable provisions of the state implementation plan and any other requirements under local, state or federal law.

(b) At such time that a particular source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforcement limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of R307-403 shall apply to the source or modification as though construction had not yet commenced on the source or modification;

(6) The provisions of R307-403-2(6)(a) through (f) apply to projects at existing emissions units at a major stationary source (other than projects at a source with a PAL) in circumstances where there is a reasonable possibility that a project that is not a part of a major modification may result in a significant emissions increase and the owner or operator elects to use the method specified in paragraphs 40 CFR 51.165(a)(1)(xxviii)(B)(1) through (3) for calculating projected actual emissions.

(a) Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

(i) A description of the project;

(ii) Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

(iii) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under 40 CFR 51.165(a)(1)(xxviii)(B)(3) and an explanation for why such amount was excluded, and any netting calculations, if applicable.

(b) If the emissions unit is an existing electric utility steam generating unit, before beginning actual construction, the owner or operator shall provide a copy of the information set out in R307-403-2(6)(a) to the reviewing authority. Nothing in this paragraph shall be construed to require the owner or operator of such a unit to obtain any determination from the reviewing authority before beginning actual construction.

(c) The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions units identified in paragraph R307-403-2(6)(a)(ii); and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

(d) If the unit is an existing electric utility steam generating unit, the owner or operator shall submit a report to the reviewing authority within 60 days after the end of each calendar year during which records must be generated under paragraph R307-403-2(6)(c) setting out the unit's annual emissions during the calendar year that preceded submission of the report.

(e) If the unit is an existing unit other than an electric utility steam generating unit, the owner or operator shall submit a report to the reviewing authority if the annual emissions, in tons per year, from the project identified in paragraph R307-403-2(6)(a), exceed the baseline actual emissions (as documented and maintained pursuant to paragraph R307-403-2(6)(c), by a significant amount (as defined in 40 CFR 51.165(a)(1)(x)) for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to paragraph R307-403-2(6) (c). Such report shall be submitted to the reviewing authority within 60 days after the end of such year. The report shall contain the following:

(i) The name, address and telephone number of the major stationary source;

(ii) The annual emissions as calculated pursuant to paragraph R307-403-2(6)(c); and

(iii) Any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

(f) A "reasonable possibility" under (R307-403-2(6) occurs when the owner or operator calculates the project to result in either:

(i) A projected actual emissions increase of at least 50 percent of the amount that is a "significant emissions increase," as defined in 40 CFR 51.165(a)(1)(xxvii)(without reference to the amount that is a significant net emissions increase), for the regulated NSR pollutant; or

(ii) A projected actual emissions increase that, added to the amount of emissions excluded under 40 CFR 51.165(a)(1)(xxviii)(B)(3), sums to at least 50 percent of the amount that is a "significant emissions increase," as defined under paragraph 40 CFR 51.165(a)(1)(xxvii) without reference to the amount that is a significant net emissions increase), for the regulated NSR pollutant. For a project for which a reasonable possibility occurs only within the meaning of this paragraph, and not also within the meaning of paragraph R307-403-2(6)(f)(i), then provisions R307-403-2(6)(b) through (e) do not apply to the project.

(7) The owner or operator of the source shall make the information required to be documented and maintained pursuant to paragraph R307-403-2(6) above available for review upon a request for inspection by the director or the general public pursuant to the requirements contained in 40 CFR 70.4(b)(3)(viii).

(8) The requirements of R307-403 applicable to major stationary sources and major modifications of volatile organic compounds shall apply to nitrogen oxides emissions from major stationary sources and major modifications of nitrogen oxides in an ozone transport region or in any ozone nonattainment area, except in ozone nonattainment areas or in portions of an ozone transport region where the EPA Administrator has granted a nitrogen oxides waiver applying the standards set forth under section 182(f) of the Clean Air Act and the waiver continues to apply.

(9) Reserved.

(10) The requirements of R307-403 apply to new major sources and major modifications to existing sources. Such sources or modifications located in or impacting areas of nonattainment for ozone, PM_{10}, or $PM_{2.5}$ shall also consider each precursor to ozone, PM_{10}, or $PM_{2.5}$ respectively. Sources or modifications determined to be major for any of these individual precursors shall[~~, for offsetting requirements,~~] also be regarded as major for that pollutant for which the area is designated nonattainment.

(a) In areas of ozone nonattainment, a new stationary source that is major for nitrogen oxides or for volatile organic compounds

shall be considered major for ozone. Similarly, a major modification to an existing source that is major for nitrogen oxides or for volatile organic compounds shall be considered major for ozone.

(b) In areas of PM_{10} nonattainment, the requirements of R307-403 applicable to major stationary sources and major modifications of PM_{10} shall also apply to major stationary sources and major modifications of nitrogen oxides and sulfur dioxides, except where the Administrator determines that such sources do not contribute significantly to PM_{10} levels that exceed the PM_{10} ambient standards in the area[~~a new stationary source that is major for nitrogen oxides or for sulfur dioxide shall trigger offset requirements for PM_{10}. Similarly, a major modification to an existing source that is major for nitrogen oxides or for sulfur dioxide shall trigger offset requirements for PM_{10}~~].

(c) In areas of $PM_{2.5}$ nonattainment, the requirements of R307-403 applicable to major stationary sources and major modifications of $PM_{2.5}$ shall also apply to major stationary sources and major modifications of any individual $PM_{2.5}$ precursor as defined in R307-403-1(4)(c)[~~a new stationary source that is major for any individual $PM_{2.5}$ precursor, as defined in R307-403-1(4)(c), shall trigger offset requirements for $PM_{2.5}$. Similarly, a major modification to an existing source that is major for any individual $PM_{2.5}$ precursor, as defined in R307-403-1(4)(c), shall trigger offset requirements for $PM_{2.5}$~~].

(11) Reserved.

(12) R307-403 applies to any major source or major modification that is located outside a nonattainment area and is major for the pollutant for which the area is designated nonattainment under section 107(d)(1)(A)(i) of the Clean Air Act and that causes the significant increments in R307-403-3(1) to be exceeded in the nonattainment area.

(13) R307-403-5 applies to any new or modified source in a PM_{10} or $PM_{2.5}$ nonattainment area.

R307-403-3. Review of Major Sources of Air Quality Impact.

Every major new source or major modification must be reviewed by the director to determine if a source will cause or contribute to a violation of the NAAQS.

(1) If the owner or operator of a source proposes to locate the source outside an area of nonattainment where the source will not cause an increase greater than the following increments in actual areas of nonattainment or in the Salt Lake City and Ogden maintenance areas for carbon monoxide and the source otherwise meets the requirements of these regulations, such source shall be approved.

TABLE

MAXIMUM ALLOWABLE MICROGRAM/CUBIC METER IMPACT
BY AVERAGING TIME

Pollutant	Annual	24-Hr	8-Hr	3-Hr	1-Hr
SULFUR DIOXIDE	1.0	5		25	
$PM_{2.5}$	0.3	1.2			
NO_2	1.0				
PM_{10}	1.0	3			
CO			500		2000

(2) If the director finds that the emissions from a proposed source would cause a new violation of the NAAQS but would not contribute to an existing violation, the director shall approve the proposed source if and only if:

(a) the new source is required to meet a more stringent emission limitation, sufficient to avoid a new violation of the NAAQS and

(b) the new source has acquired sufficient offset to avoid a new violation of the NAAQS and

(c) the new emission limitations for the proposed source and for any affected existing sources are enforceable.

(3) For a proposed new major stationary source or major modification that is major for a pollutant, or any individual precursor to that pollutant, for which an area is designated nonattainment, approval shall be granted if and only if:

(a) the new major source or major modification meets an emission limitation which is the Lowest Achievable Emission Rate (LAER) for such source for the relevant pollutant(s) in the respective nonattainment area;

(b) the applicant has certified that all existing major sources in the State, owned or controlled by the owner or operator (or by any entity controlling, controlled by or under common control with such owner or operator) of the proposed source, are in compliance with all applicable rules in R307, including the Utah Implementation Plan requirements or are in compliance with an approved schedule and timetable for compliance under the Utah Implementation Plan, R307, or an enforcement order, and that the source is complying with all requirements and limitations as expeditiously as practicable;

(c) emission offsets to the extent provided in R307-403-4, R307-403-5, and R307-403-6 are sufficient such that there will be reasonable further progress toward attainment of the applicable NAAQS;

(d) the emission offsets provide a positive net air quality benefit in the affected area of nonattainment; and,

(e) [~~there is an approved implementation plan in effect for the pollutant to be emitted by the proposed source~~]the restrictions on new or modified sources identified in 40 CFR 52.24 are not applicable.

(4) A source which is locating outside a nonattainment area or the Salt Lake City and Ogden maintenance areas for carbon monoxide and which causes the significant increments in R307-403-3(1) to be exceeded in the nonattainment or maintenance area is subject to the requirements of R307-403-3(3).

R307-403-4. Offsets: General Requirements.

(1) All general offset permitting requirements apply for all offsets regardless of the pollutant at issue. General offset permitting requirements shall be imposed immediately and directly on all new major stationary sources or major modifications located in a nonattainment area that are major for the pollutant, or any individual precursor to the pollutant, for which the area is designated nonattainment.

(2) Emission offsets must be obtained from the same source or other sources in the same nonattainment area except that the owner or operator of a source may obtain emission offsets in another nonattainment area if:

(a) the other area has an equal or higher nonattainment classification than the area in which the source is located; and

(b) emissions from such other area contribute to a violation of the national ambient air quality standard in the nonattainment area in which the source is located or which is impacted by the source.

(3) Any emission offsets required for a new or modified source shall be in effect and enforceable before a new or modified source commences construction. The new or modified source shall assure that the total tonnage of increased emissions of the air pollutant from the new or modified source shall be offset by an equal or greater reduction, as applicable, in the actual emissions of such air pollutant from the same or other sources in the area. Offsets may not be traded between pollutants, except as required only to satisfy R307-403-5(1) where it pertains to emission increases that are not considered major for PM_{10} or a PM_{10} precursor.

(4) Emission offsets must be surplus, permanent, quantifiable, and federally enforceable. Emission reductions otherwise required by the federal Clean Air Act or R307, including the State Implementation Plan shall not be creditable as emission reductions for purposes of any offset requirement. Incidental emission reductions which are not otherwise required by federal or state law shall be creditable as emission reductions if such emission reductions meet the requirements of R307-403-4(2) and R307-403-4(3).

(5) Sources shall be allowed to offset, by alternative or innovative means, emission increases from rocket engine and motor firing, and cleaning related to such firing, at an existing or modified major source that tests rocket engines or motors under the conditions

outlined in 42 U.S.C. 7503(e) (Section 173(e)(1) through Section 173(e)(4) of the federal Clean Air Act as amended in 1990).

R307-403-5. Offsets: Particulate Matter Nonattainment Areas.

(1) PM_{10} Nonattainment Areas. (a) In addition to the general offsetting requirements of R307-403-4, as they apply to new major sources and major modifications as defined in R307-403-2(10)(b), n[~~N~~]ew sources which have a potential to emit, or modified sources which would produce an emission increase equal to or exceeding the tonnage total of combined PM_{10}, sulfur dioxide, and oxides of nitrogen listed below which are located in or impact a PM_{10} Nonattainment Area as defined in R307-403-5(1)(~~a~~e), shall obtain an enforceable offset as defined in R307-403-5(1)(b) and R307-403-5(1)(c).

[~~(a) For the purpose of determining whether the owner or operator which proposes to locate a source outside a nonattainment area is required to obtain offsets, the maximum allowable impact on any nonattainment area is 1.0 microgram/cubic meter for a one-year averaging period and 3.0 micrograms/cubic meter for a 24-hour averaging period for any combination of PM_{10}, sulfur dioxide and nitrogen dioxide.~~]

(b) For a total of 50 tons/year or greater, an offset established at a ratio of 1.2:1 of the emission increase is required.

(c) For a total of 25 tons/year but less than 50 tons/year, an offset established at a ratio of 1:1 of the emission increase is required.

(d) For the offset determinations required in R307-403-5(1)(b) or R307-403-5(1)(c), PM_{10}, sulfur dioxide, and oxides of nitrogen shall be considered on an equal basis. In areas where offsets are also required for [~~PM_{10},~~]$PM_{2.5}$, and/or ozone, the most stringent emission offset ratio for oxides of nitrogen required by R307-403 or R307-420 shall apply.

(e) For the purpose of determining whether the owner or operator which proposes to locate a source outside a nonattainment area is required to obtain offsets, the maximum allowable impact on any nonattainment area is 1.0 microgram/cubic meter for a one-year averaging period and 3.0 micrograms/cubic meter for a 24-hour averaging period for any combination of PM_{10}, sulfur dioxide and nitrogen dioxide.

(2) $PM_{2.5}$ Nonattainment Areas. [~~For the purposes of $PM_{2.5}$ nonattainment areas a major source is:~~

]~~———~~(a) In addition to the general offsetting requirements of R307-403-4, new major sources or major modifications to existing sources which are located in, or would impact a $PM_{2.5}$ nonattainment area as defined in R307-403-3(1), shall obtain an enforceable offset as defined in R307-403-5(2)(d) through (f).

(b) a major source is:

(i) in a moderate nonattainment area, any stationary source of air pollutants which emits or has the potential to emit 100 tons per year or more of direct $PM_{2.5}$, or any individual $PM_{2.5}$ precursor as defined in R307-403-1(4)(c).

(~~b~~ii) in a serious nonattainment area, any stationary source of air pollutants which emits or has the potential to emit 70 tons per year or more of direct $PM_{2.5}$, or any individual $PM_{2.5}$ precursor as defined in R307-403-1(4)(c).

(~~c~~iii) any physical change that would occur at a source not qualifying under R307-403-5(2)(~~a~~b)(i) or R307-403-5(2)(b)(ii) as a major source, if the change would constitute a major source by itself.

[~~(d) in $PM_{2.5}$ nonattainment areas, a new stationary source that is major for any individual $PM_{2.5}$ precursor as defined in R307-403-1(4)(c) shall be considered major for $PM_{2.5}$. Similarly, a major modification to an existing source that is major for any individual $PM_{2.5}$ precursor as defined in R307-403-1(4)(c) shall be considered major for $PM_{2.5}$.~~

~~(4) New major sources or major modifications to existing sources which are located in, or would impact a $PM_{2.5}$ Nonattainment area as defined in R307-403-5(4)(b), shall obtain an enforceable offset as defined in R307-403-5(4)(c) through R307-403-5(4)(e).~~]

(~~a~~c) For the purposes of determining what is a significant emission increase or a significant net emission increase and therefore a major modification, significant means a rate of emissions that would equal or exceed 10 tons per year (tpy) of direct $PM_{2.5}$, 40 tpy of sulfur dioxide, 40 tpy of nitrogen oxides, or 40 tpy of volatile organic compounds (VOC). In $PM_{2.5}$ nonattainment areas where ammonia has not been exempted as a $PM_{2.5}$ precursor, the rate of emissions that is significant is specified in R307-403-1(4)(b).

[~~(b) For the purpose of determining whether the owner or operator which proposes to locate a source outside a nonattainment area is required to obtain offsets, the maximum allowable impact on any $PM_{2.5}$ nonattainment area is 0.3 microgram/cubic meter for a one-year averaging period and 1.2 micrograms/cubic meter for a 24-hour averaging period for direct $PM_{2.5}$.~~]

(~~c~~d) Any increase in emissions that has been determined to require offsets shall be offset at a ratio of no less than 1:1. If the quantity of offsets is determined to be a non-whole number, the offset required shall be rounded up to the next whole number.

(~~d~~e) [~~In areas where offsets may also be required for precursors to PM_{10} and/or ozone~~]If offsetting requirements for PM_{10} and/or ozone are also triggered, the most stringent emission offset ratio required by R307-403 or R307-420 shall apply.

(~~e~~f) Offsets may not be traded between pollutants.

R307-403-6. Offsets: Ozone Nonattainment Areas.

In any ozone nonattainment area, new sources and modifications to existing sources as defined and outlined in 42 U.S.C. 7511a (Section 182 of the Clean Air Act) shall meet the offset requirements and conditions listed in that section for the applicable classified area and for the identified pollutants.

R307-403-7. Offsets: Baseline.

The baseline to be used for determination of credit for emission and air quality offsets will be the emission limitations and/or other requirements in the applicable State Implementation Plan (SIP), revised in accordance with the Clean Air Act Section 173(c)(1) or subsequent revisions thereto in effect at the time the application to construct or modify a source is filed. The offset baseline shall be the actual emissions, as defined in R307-401-2, of the source from which offset credits are obtained.

R307-403-8. Offsets: Banking of Emission Offset Credit.

Banking of emission offset credit will be permitted to the fullest extent allowed by applicable Federal Law as identified in EPA's document "Emissions Trading Policy Statement" published in the Federal Register on December 4, 1986, and 40 CFR 51.165(a)(3)(ii)(c) as amended on June 28, 1989, and 40 CFR 51, Appendix S. To preserve banked emission reductions, the director must identify them in either the Utah SIP or an order issued pursuant to R307-401 and shall provide a registry to identify the person, private entity or governmental authority that has the right to use or allocate the banked emission reductions, and to record any transfers of, or liens on these rights.

R307-403-9. Construction in Stages.

When a source is constructed or modified in stages which individually do not have the potential to emit more than the significance level for determining a major source, the allowable emission from all such stages shall be added together in determining the applicability of R307-403.

R307-403-10. Analysis of Alternatives.

The owner or operator of a major new source or major modification to be located in a nonattainment area or which would impact a nonattainment area must, in addition to the requirements in R307-403, submit with the notice of intent an adequate analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source which demonstrates the benefits of the proposed source significantly outweigh the environmental and

social costs imposed as a result of its location, construction, or modification. The director shall review the analysis. The analysis and the director's comments shall be subject to public comment as required by R307-401-7. The preceding shall also apply in Salt Lake and Davis Counties for new major sources or modifications which are considered major for precursors of ozone, including volatile organic compounds and nitrogen oxides.

R307-403-11. Actuals PALS.

The provisions of 40 CFR 51.165(f)(1) through (14) are hereby incorporated by reference.

KEY: air quality, nonattainment, offset
Date of Enactment or Last Substantive Amendment: 2018
Notice of Continuation: May 15, 2017
Authorizing, and Implemented or Interpreted Law: 19-2-104; 19-2-108

ITEM 5

State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-034-18

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Bill Reiss, Environmental Engineer

DATE: May 24, 2018

SUBJECT: FINAL ADOPTION: Change in Proposed Rule R307-101-2. Definitions.

On March 7, 2018, the Utah Air Quality Board proposed amendments to R307-101-2. The rule had been amended to update the definition of "PM2.5 Precursor," adding ammonia to the list of PM2.5 precursors, and accommodating provisions in the federal PM Implementation Rule (40 CFR 51, Subpart Z) which allow for demonstrations exempting any PM2.5 precursor from certain requirements in specific PM2.5 nonattainment areas.

A public comment period was held from April 1 to April 30, 2018. No hearing was requested. Staff received one written comment on this proposal that is summarized below.

Response to Comment

EPA Region 8 Comment #1. Regarding R307-101-2. Definitions; Revisions to the Definition of "PM2.5 Precursor"

The revisions to R307-101-2 add paragraph (1), which states:

> Specifically, sulfur dioxide, nitrogen oxides, volatile organic compounds and ammonia are precursors to PM2.5 in any PM2.5 nonattainment area, except where a demonstration satisfying 40 CFR 51.1006(a)(3) has, for a particular PM2.5 nonattainment area, determined otherwise.

For the same reasons mentioned above, we recommend the following revision to paragraph (1):

> Specifically, sulfur dioxide, nitrogen oxides, volatile organic compounds and ammonia are precursors to PM2.5 in any PM2.5 nonattainment area, except where the Administrator of the EPA has approved a demonstration satisfying 40 CFR 51.1006(a)(3) which has, for a particular PM2.5 nonattainment area, determined otherwise.

DAQ Response: DAQ agrees, and will make the recommended clarification.

Recommendation: Staff recommends that the Board adopt the Change in Proposed Rule R307-101-2. Definitions.

R307. Environmental Quality, Air Quality.
R307-101. General Requirements.
R307-101-2. Definitions.

"PM2.5 Precursor" means any chemical compound or substance which, after it has been emitted into the atmosphere, undergoes chemical or physical changes that convert it into particulate matter, specifically PM2.5.

(1) Specifically, Sulfur dioxide, Nitrogen oxides, Volatile organic compounds and Ammonia are precursors to PM2.5 in any PM2.5 nonattainment area, except where the Administrator of the EPA has approved a demonstration satisfying 40 CFR 51.1006(a)(3) which has, for a particular PM2.5 nonattainment area, determined otherwise.

(2) The following subparagraphs denote specific nonattainment areas (as defined in the July 1, 2017 version of 40 CFR 81.345), within which certain pollutants identified in paragraph (1) are exempted from the definition of PM2.5 precursor for the purposes of 40 CFR 51.165

(a) In the Logan UT-ID PM2.5 nonattainment area - Ammonia is exempted.

KEY: air pollution, definitions
Date of Enactment or Last Substantive Amendment: 2018
Notice of Continuation: May 8, 2014
Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)

ITEM 6

State of Utah

GARY R. HERBERT
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SPENCER J. COX
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Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-033-18

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Joel Karmazyn, Environmental Scientist

DATE: May 22, 2018

SUBJECT: FINAL ADOPTION: Revision to Carbon Monoxide Maintenance Plan, Provo Area, State Implementation Plan, Section IX, Part C

In 1993-94, it was determined through modeling that the only areas in Utah County where carbon monoxide (CO) violations were potentially occurring were in Provo and Orem. The Provo and Orem areas were subsequently classified as one moderate non-attainment area. On September 20, 2002, the Environmental Protection Agency (EPA) published a determination that the Provo nonattainment area had attained the CO national ambient air quality standard (NAAQS) by December 31, 1995. EPA subsequently approved a vehicle inspection and maintenance (I/M) program and an oxygenated fuels program. On November 2, 2005, the EPA approved the Provo CO redesignation request to attainment and the first 10-year maintenance plan.

On March 7, 2018, the Board proposed revisions to the Provo Area Carbon Monoxide Maintenance Plan for public comment. At the same meeting, the Board recommended the language "…vehicles that were manufactured in 1995 or later" be corrected to read "…vehicles that were manufactured in 1995 or earlier" as part of the public comment process. Additionally, Susan Harding of Mountainland Association made additional comments during the meeting, concurring with the plan revisions.

The public comment period was held from April 1 through April 30, 2018. No comments were received during this period.

Recommendation: Staff recommends that the Board adopt amended Carbon Monoxide Maintenance Plan, Provo Area, as proposed.

Carbon Monoxide Maintenance Plan
Provo Area

State Implementation Plan Section IX, Part C.6
Revision

2018

UTAH DEPARTMENT of ENVIRONMENTAL QUALITY
AIR QUALITY

1. Background

In 1993-94, it was determined through modeling that the only areas in Utah County where carbon monoxide (CO) violations were potentially occurring were in Provo and Orem. The Provo and Orem areas were subsequently classified as one moderate non-attainment area. On September 20, 2002 (67 FR 59165), the Environmental Protection Agency (EPA) published a determination that the Provo nonattainment area had attained the CO national ambient air quality standard (NAAQS) by December 31, 1995. EPA subsequently approved a vehicle inspection and maintenance (I/M) program and an oxygenated fuels program. On November 2, 2005, the EPA approved the Provo CO redesignation request to attainment and the first 10-year maintenance plan (70 FR 66264).

The purpose of this revision to the Provo Area CO Attainment-Maintenance Plan is to:

1. Show continued attainment of the CO NAAQS for a second 10-year term, as required by the Clean Air Act; and

2. To adopt an alternative CO monitoring method that does not utilize the traditional gaseous analyzer to determine compliance with the NAAQS. The alternative monitoring method will utilize an annual review of the traffic volume near the current location of the North Provo monitoring station.

2. Limited Maintenance Plan Option

Utah is using the Limited Maintenance Plan (LMP) option in preparing this second 10-year revision. EPA provides this less rigorous approach in developing a maintenance plan for CO attainment-maintenance areas that have a design value at or below 7.65 ppm. The design value for the Provo area is 2.1 ppm. The design value was determined by using the highest second-highest maximum 8-hour value from 2015 through 2016. This value is referred to as “the highest of the second highs” in a June 18, 1990 EPA memo from William G. Laxton that describes how to establish design values for CO.

The limited maintenance plan approach requires development of an emissions inventory but does not require the inventory to be projected for future years. The maintenance demonstration is considered to be satisfied if the monitoring data show that the area is meeting the air quality criteria for limited maintenance areas (at or below 7.65 ppm or 85 percent of the CO NAAQS).

3. Transportation Conformity

Once EPA approves this Plan, there will no longer be a need to demonstrate conformity with any motor vehicle emission budget for the Provo CO maintenance area, for the reasons described in EPA’s LMP guidance. From that point forward, all actions that require conformity determinations for the Provo CO maintenance area under EPA’s conformity rule provisions will be considered to have already satisfied the regional emissions analysis and “budget test” requirements in 40 CFR 93.118.

However, since LMP areas are still maintenance areas, certain aspects of transportation conformity determinations still will be required for transportation plans, programs and projects. Specifically, regional transportation plans, transportation improvement programs

and transportation projects will need to continue to demonstrate that they are fiscally constrained (40 CFR 93.108) and meet the criteria for consultation and transportation control measure implementation (as appropriate) as noted in EPA's conformity rule provisions (40 CFR 93.112 and 40 CFR 93.113, respectively). In addition, projects in LMP areas still will be required to meet the applicable criteria for CO hot spot analyses to satisfy "project level" conformity determinations (40 CFR 93.116 and 40 CFR 93.123), which must also incorporate the latest planning assumptions and models available (40 CFR 93.110 and 40 CFR 93.111, respectively).

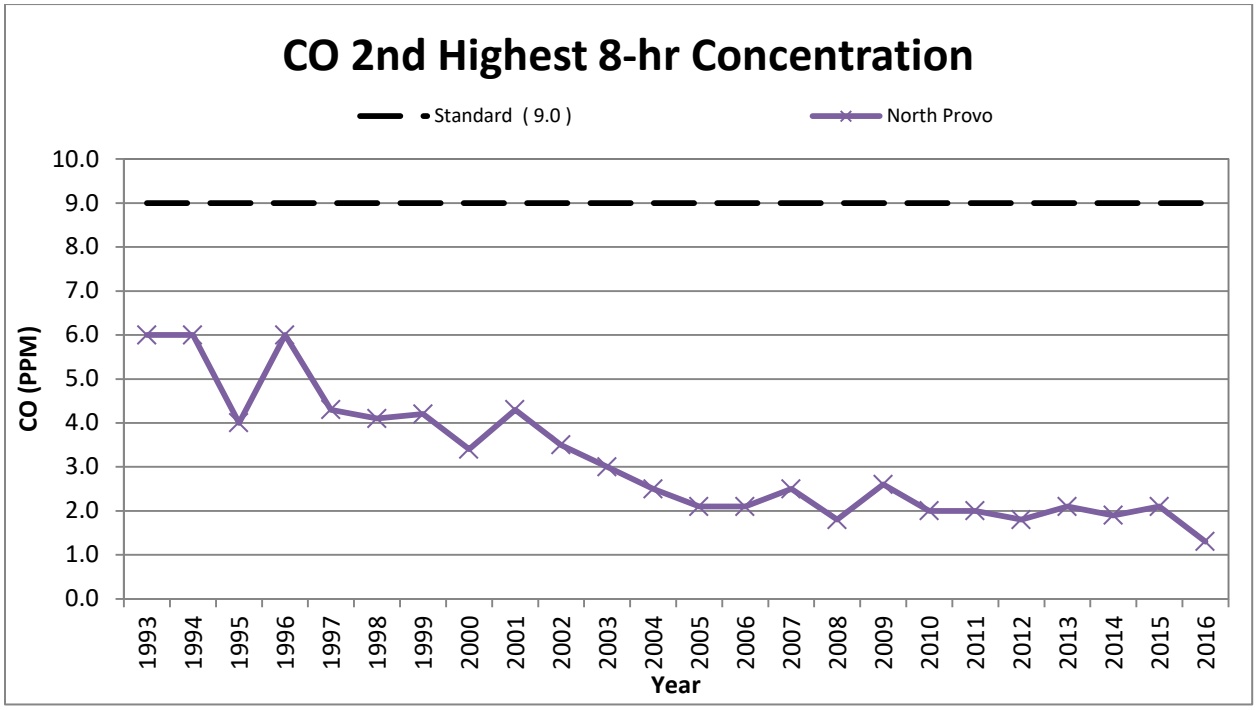
4. Maintenance Demonstration

Under the EPA's LMP option, the maintenance demonstration is considered to be satisfied if the monitoring data shows that the area is meeting the air quality criteria for limited maintenance areas (at or below 7.65 ppm or 85 percent of the CO NAAQS). The design value for the Provo CO Attainment/Maintenance Area is 2.1 ppm,(23 percent of the CO NAAQS), which is the highest second maximum concentration for the 2015-2016 monitoring period. Therefore, the maintenance demonstration is satisfied.

Continued Attainment of the Carbon Monoxide Standard

Air Quality Monitoring

Due primarily to improvements in motor vehicle technology, the Provo area monitor data shows that the area has been in compliance with the CO standard since 1993, as shown in the graph below. Since a monitor must not exceed the NAAQS of 9.0 ppm more than once a year, the second highest 8-hour value each year is the indicator of attainment.



Vehicle Inspection and Maintenance (I/M) Program

The I/M program in place in Utah County consists of the following:

- New vehicles are exempt for two years;
- On-board diagnostics (OBD) henceforth every other year for [~~four years~~]vehicles less than six years old;
- Subsequently, OBD every year for vehicles of model years 1996 and newer (except for vehicles less than six years old; and
- Two Speed Idle test for vehicles of model years 1968-1995[~~that were manufactured in 1995 or later~~].

5. Emission Inventory

This plan revision utilizes the 2016 emissions inventory, which is the most current CO inventory that covers the period in which the design value was derived. The emission inventory for Utah County is for a typical winter day.

Emission Inventory Summary	**CO (tons/day)**
Point Sources	0.901
Onroad Mobile	94.827
Nonroad Mobile	27.769
Railroads	0.255
Wood Burning	6.454
Commercial Cooking	0.137
Nat. Gas Fuel Combustion	3.144
TOTAL	**133.488**

Ninety two percent of the CO is derived from mobile sources; consequently, we can focus the Maintenance Plan on mobile sources in the Provo Area. The Utah Department of Transportation (UDOT) provided the Utah Division of Air Quality (UDAQ) with Provo-specific vehicle mileage for the winter months of November through February, when CO levels are at their highest concentration. The MOVES2014a model was used to calculate average winter day CO levels in tons per day for years 2011, 2014 and 2016.

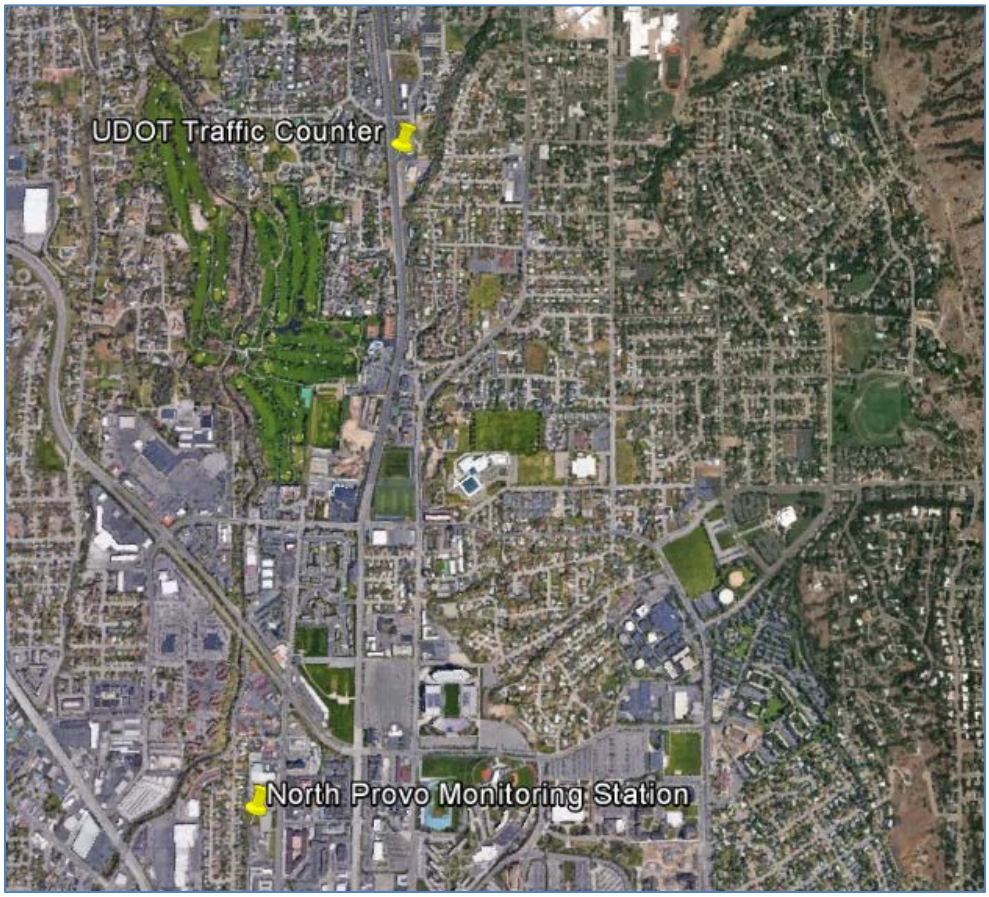
Year	**Vehicle Miles Traveled/Winter Day in Provo City**	**Average CO Tons/Day In Provo City**
2011	1,255,778	16.53
2014	1,312,491	14.46
2016	1,497,156	13

CO levels have declined while vehicles miles have increased. This is attributed to cleaner vehicles. Under the Tier 2 Motor Vehicle Emission Standards, which were phased in between 2004 and 2009, the average new vehicle had a full useful life CO emission standard of 4.2 grams/mile. Under the Tier 3 Motor Vehicle Emission Standards, phased in between 2017 and 2025, the average new vehicle will have a CO emission standard of 1 gram/mile. This represents a 76.2 % reduction in CO for the average new light-duty vehicle. As CO emissions will continue to decline, it is unlikely that a violation of the 8-Hour CO standard will occur.

Local air monitoring has shown that the CO levels have been steady for the past 11 years. This would suggest that the current traffic count near the monitoring station can be used as a proxy monitoring method.

6. Mobile Counts

A UDOT counter located near 3200 North University Avenue (coordinates 40.275905, -111.657356) is located approximately 1.7 miles from the North Provo monitoring station. The Google Earth map shows the locations of the monitoring station and the counter.



The daily average traffic (DAT) during November through February at the counter:

Year	November	December	January	February	Averages
2013-2014	27,223	24,881	27,361	28,679	27,036
2014-2015	28,453	27,156	29,056	30,682	28,837
2015-2016	29,582	27,518	30,452	32,301	29,963
					28,612

Source: Nicolas Virgen, UDOT Traffic Analyst Supervisor

7. Verification of Continued Attainment

The alternative CO monitoring method will comprise of obtaining the ADT from the UDOT counter to monitor mobile source growth. If the counter is relocated or taken out of service, UDAQ will advise EPA to determine the appropriate action, which may include identifying an alternative counter.

If the rolling 3-year ADT value is 25% higher than the average value of 28,612 from the 2013–2016 baseline period, UDAQ will reinstitute gaseous monitoring within the maintenance area. The monitoring will be conducted the following winter from November to February, and the results evaluated to determine if the levels of CO emissions in the area appear to be rising commensurate with the increase in traffic counts. If the monitored 2nd maximum value for that time period has not increased from the baseline mean by an equal or greater rate at which the traffic counts have increased and the monitor values remain at or below 50% of the CO NAAQS (2nd max concentration ≤2.1 ppm currently), the monitor may again be removed and the traffic counts resumed.

8. Enforceable Control Measures for the Maintenance Period

- Utah Administrative Rule R307-401, New and Modified Sources. BACT analysis required for all NAAQS.

- Utah Administrative Rule R307-302-4, Solid Fuel Burning Devices. Establishes no-burn periods for CO.

9. Contingency Plan

Section 175A(d) of the Clean Air Act requires that maintenance plans assure prompt action to correct any violation of the standard that occurs after the area is re-designated to attainment. Additional controls are to be implemented to achieve sufficient CO emission reductions to eliminate any future CO violations. The triggering of contingency measures does not automatically require a revision to the SIP or re-designation to nonattainment. Contingency measures typically have several steps for action depending on the severity of air quality. The following apply to this LMP.

1. If the ADT grows by more than 25% over a rolling 3-year average as described in Section 7 of this plan, UDAQ will reinstitute gaseous monitoring within the maintenance area. The monitoring will be conducted the following winter from November to February and the results evaluated to determine if the levels of CO emissions in the area appear to be rising commensurate with the increase in traffic counts.

2. Once monitoring is reinstated, if the highest measured 8-hour CO concentration in a given year exceeds the LMP eligibility level of 7.65 ppm, UDAQ will evaluate the cause of the CO increase. Within 6 months of the validated 7.65 ppm concentration, UDAQ will present the Utah Air Quality Board with a recommended strategy to either prevent or correct any violation of the 8-hour CO standard.

3. If a violation of the CO standard occurs (2 exceedances of 9 ppm in the same calendar year), the Utah Air Quality Board, in consultation with the UDAQ, will hold a public meeting to consider the prior contingency measures that helped to bring the Provo area into attainment such as a mandatory 2.7% oxygen fuels program and annual I/M tests. These measures would be considered in addition to any other potential measures to help the Provo area to reduce CO emissions. The Utah Air Quality Board would then adopt and require the implementation of the selected contingency measure(s) by November 1st of the next winter season.

ITEM 7

State of Utah

GARY R. HERBERT
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SPENCER J. COX
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Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-032-18

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Thomas Gunter, Rules Coordinator

DATE: May 22, 2018

SUBJECT: FINAL ADOPTION: Amend R307-110-12. Section IX, Control Measures for Area and Point Sources, Part C, Carbon Monoxide.

On March 7, 2018, the Board proposed for public comment an amendment to R307-110-12, which would incorporate amendments to Section IX, Control Measures for Area and Point Sources, Part C, for Carbon Monoxide, into the Utah Air Quality Rules.

The public comment period was held from April 1 through April 30, 2018. No comments were received.

Staff Recommendation: Staff recommends that the Board adopt amended R307-110-12.

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R307. Environmental Quality, Air Quality.
R307-110. General Requirements: State Implementation Plan.

R307-110-12. Section IX, Control Measures for Area and Point Sources, Part C, Carbon Monoxide.

The Utah State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part C, Carbon Monoxide, as most recently amended by the Utah Air Quality Board on June 6, 2018, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

KEY: air pollution, PM10, PM2.5, ozone
Date of Enactment or Last Substantive Amendment: 2018
Notice of Continuation: January 27, 2017
Authorizing, and Implemented or Interpreted Law: 19-2-104

ITEM 8

State of Utah

GARY R. HERBERT
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Department of
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Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-037-18

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Bill Reiss, Environmental Engineer

DATE: May 24, 2018

SUBJECT: PROPOSE FOR PUBLIC COMMENT: Amend SIP Subsection IX. Part H: Emission Limits and Operating Practices. Specifically Proposed for Amendment are Requirements in Subparts H. 1, 2, 11, and 12.

On December 7, 2016, the Board adopted SIP Subsection IX. Part H. subparts 11 and 12: Control Measures for Area and Point Sources, Emission Limits and Operating Practices, PM2.5 Requirements. The terms in these subparts enforce the plan requirements for stationary sources located in the Salt Lake City $PM_{2.5}$ nonattainment area. After the Board adopted Part H, the Governor submitted it to EPA as part of the Moderate Area $PM_{2.5}$ State Implementation Plan (SIP).

On June 9, 2017, the Environmental Protection Agency (EPA) effectively reclassified the Salt Lake nonattainment area from Moderate to Serious. The reclassification means that, in addition to the moderate area planning requirements, the Clean Air Act now requires Utah to submit a Serious area nonattainment plan. A Serious area nonattainment plan includes provisions for the implementation of best available control measures, including control technologies (BACM/BACT) and includes enforceable emission limitations as well as schedules and timetables for compliance. The emission limits and operating practices expressed in Part H. subparts 11 and 12 have been developed to meet this requirement with respect to the large stationary "point" sources within the $PM_{2.5}$ nonattainment area. Changes to Part H. subparts 1, and 2: Control Measures for Area and Point Sources, Emission Limits and Operating Practices, PM_{10} Requirements were included to correct a calculation error and add clarification and consistency throughout Part H.

EPA's Fine Particulate Matter Implementation Rule explains that BACM/BACT is "generally independent" of attainment, and is to be determined without regard to the specific attainment demonstration for the area. For this reason, the Division of Air Quality (DAQ) is presenting the Air Quality

Board an opportunity to release the proposed revisions to Part H for public review and comment prior to the completion of the accompanying modeling and attainment demonstration.

Recommendation: Staff recommends that the Board propose for public comment SIP Subsection IX. Part H: Emission Limits and Operating Practices, as amended in subparts 1, 2, 11, and 12.

Utah State Implementation Plan

Emission Limits and Operating Practices

Section IX, Part H

Adopted by the Air Quality Board
[~~December 7~~], 201[~~6~~]8

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

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

b. Definitions.

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

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

c. Recordkeeping and Reporting

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

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

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

d. Emission Limitations.

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

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

e. Stack Testing.

   i. As applicable, stack testing to show compliance with the emission limitations for the sources in Subsection IX.H.2 and I.X.H.3 shall be performed in accordance with the following:

A. Sample Location: The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other EPA-approved testing methods acceptable to the Director. Occupational Safety and Health Administration (OSHA) approvable access shall be provided to the test location.

B. Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2 or other EPA-approved testing methods acceptable to the Director.

C. PM_{10}: [~~The following methods shall be used to measure condensable particulate emissions:~~]40 CFR 51, Appendix M, Methods [~~201 or~~]201a and 202, or other EPA approved testing methods acceptable to the Director. If a method other [~~approved testing methods are used which cannot measure the PM10 fraction of the filterable particulate emissions, all of the filterable particulate emissions shall be considered PM10. The following methods shall be used to measure condensable particulate emissions: 40CFR 51, Appendix M, Method 202, or other EPA-approved testing method, as~~]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.

f. Continuous Emission and Opacity Monitoring.

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

A. Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of unaffected source shall continuously operate all required continuous monitoring systems and shall meet minimum frequency of operation requirements as outlined in R307-170 and 40 CFR 60.13. Flow measurement shall be in accordance with the requirements of40 CFR 52, Appendix E; 40 CFR 60 Appendix B; or 40 CFR 75, Appendix A.

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

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

g. Petroleum Refineries.

i. Limits at Fluid Catalytic Cracking Units (FCCU)

A. FCCU SO_2 Emissions

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

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

B. FCCU PM Emissions

I. [~~By no later than January 1, 2018, e~~]Each owner or operator of an FCCU shall comply with an emission limit of 1.0 pounds PM per 1000 pounds coke burned on a 3-hour average basis.

II. Compliance with this limit shall be determined by following the stack test protocol specified in 40 C.F.R. §60.106(b) or 40 C.F.R. §60.104a(d) to measure PM emissions on the FCCU. Each owner operator shall conduct stack tests once every three (3) years at each FCCU.

III. [~~By n~~]No later than January 1, 2019, each owner or operator of an FCCU shall install, operate and maintain a continuous parameter monitor system (CPMS) to measure and record operating parameters from the FCCU for determination of source-wide [~~PM_{10}~~-]particulate emissions as per the requirements of 40 CFR 60.105a(b)(1).

ii. Limits on Refinery Fuel Gas.

A. All petroleum refineries in or affecting any $PM_{2.5}$ nonattainment area or any PM_{10} nonattainment or maintenance area shall reduce the H_2S content of the refinery plant gas to 60 ppm or less as described in 40 CFR 60.102a. Compliance shall be based on a rolling average of 365 days. The owner/operator shall comply with the

fuel gas monitoring requirements of 40 CFR 60.107a and the related recordkeeping and reporting requirements of 40 CR 60.108a. As used herein, refinery "plant gas" shall have the meaning of "fuel gas" as defined in 40 CFR 60.101a, and may be used interchangeably.

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

iii. Sulfur Removal Units

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

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

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

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

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

iv. No Burning of Liquid Fuel Oil in Stationary Sources

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

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

v. Requirements on Hydrocarbon Flares.

A. [~~Beginning January 1, 2018, a~~]All hydrocarbon flares at petroleum refineries located in or affecting a designated PM[~~10~~]$_{2.5}$ non-attainment area [~~or maintenance area~~]within the State shall be subject to the flaring requirements of NSPS Subpart Ja (40 CFR 60.100a–109a), if not already subject under the flare applicability provisions of Ja.

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

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

a. Big West Oil Company

i. Source-wide PM_{10} Cap

[~~By n~~]No later than January 1, 2019, combined emissions of PM_{10} shall not exceed 1.037 tons per day (tpd).

A. Setting of emission factors:

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

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

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

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

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

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

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

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

PM_{10} stack testing on the FCC shall be performed initially no later than January 1, 2019 and at least once every three (3) years thereafter. Stack testing shall be performed as outlined in IX.H.1.e.

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

Total 24-hour PM_{10} emissions for the emission points shall be calculated by

adding the daily results of the PM_{10} emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers, and the FCCs to arrive at a combined daily PM_{10} emission total.

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

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

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

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

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

E = FR * EF

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

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

ii. Source-Wide NO_x Cap

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

A. Setting of emission factors:

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

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

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

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

Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment above 40 MMBtu/hr has been performed and the next stack test shall be performed within 3 years of the [~~next~~]previous stack test. At that time a new flow-weighted average emission factor in terms of lbs/MMbtu shall be derived for each combustion type listed in IX.H.2.a.ii.A above. Stack testing shall be performed as outlined in IX.H.1.e.

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

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

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

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

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

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

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

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

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

iii. Source-Wide SO_2 Cap

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

A. Setting of emission factors:

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

Natural Gas - 0.60 lb SO_2/MMscf gas

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

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

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

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

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

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

The daily $SO[_2]_x$ emission from the FCC shall be calculated using [~~the following equation: SO_2 = FG * (ADV/1,000,000) * (64 lb/mole) * (operating hours/day) / (2000 lb/ton)~~]a CEM as outlined in IX.H.11.f.
[~~Where:~~
~~FG = Flue Gas in moles/hour~~
~~ADV = average daily value from SO_2 CEM as outlined in IX.H.1.f~~]

Daily natural gas and plant gas consumption shall be determined through the

use of flow meters.

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

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

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

iv. Emergency and Standby Equipment

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

v. Alternate Startup and Shutdown Requirements

A. During any day which includes startup or shutdown of the FCCU, combined emissions of SO_2 shall not exceed 1.2 tons per day (tpd). For purposes of this subsection, a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

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

vi. Requirements on Hydrocarbon Flares

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

b. Bountiful City Light and Power: Power Plant

i. Emissions to the atmosphere shall not exceed the following rates and concentrations:

A. GT #1 (5.3 MW Turbine)
Exhaust Stack: 0.6 g NO_x / kW-hr

B. GT #2 and GT #3 (each TITAN Turbine) Exhaust Stack: 7.5 lb NO_x / hr

ii. Compliance to the above emission limitations shall be determined by stack test. Stack testing shall be performed as outlined in IX.H.1.e.

A. Initial stack tests have been performed. Each turbine shall be tested at least once per year.

iii. Combustion Turbine Startup / Shutdown Emission Minimization Plan

A. Startup begins when natural gas is supplied to the combustion turbine(s) with the intent of combusting the fuel to generate electricity. Startup conditions end within sixty (60) minutes of natural gas being supplied to the turbine(s).

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

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

c. Central Valley Water Reclamation Facility: Wastewater Treatment Plant

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

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

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

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

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

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

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

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

d. Chevron Products Company

i. Source-wide PM_{10} Cap

[~~By n~~]No later than January 1, 2019, combined emissions of PM_{10} shall not exceed 0.715 tons per day (tpd).

A. Setting of emission factors:

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

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

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

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

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

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

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

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

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

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

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

Total 24-hour PM_{10} emissions for the emission points shall be calculated by adding the daily results of the PM_{10} emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers, and the FCC to arrive at a combined daily PM_{10} emission total. For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

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

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

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

ii. Source-wide NO_x Cap

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

A. Setting of emission factors:

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

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

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

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

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

Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr has been performed and shall be conducted at least once every three (3) years from the date of the [~~last~~]previous stack test. At that time a new flow-weighted

average emission factor in terms of: lbs/MMbtu shall be derived for each combustion type listed in IX.H.2.d.ii.A above. Stack testing shall be performed as outlined in IX.H.1.e.

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

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

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

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

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

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

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

iii. Source-wide SO_2 Cap

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

A Setting of emission factors:

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

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

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

Natural gas: EF = 0.60 lb/MMscf

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

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

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

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

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

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

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

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

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

iv. Emergency and Standby Equipment and Alternative Fuels

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

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

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

<u>v. Compressor Engine Requirements</u>

<u>A. Emissions of NO_x from each rich-burn compressor engine shall not exceed the</u>

following:

Engine Number	NO_x in ppmvd @ 0% O_2
1	236
2	208
3	230

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

e. Hexcel Corporation: Salt Lake Operations

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

A. 5.50 MMscf of natural gas consumed per day.

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

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

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

II. Fiber production shall be determined by examination of plant production records. III. Records of consumption and production shall be kept on a daily basis for all periods when the plant is in operation.

ii. After a shutdown and prior to startup of fiber lines 13, 14, 15, or 16, the line's baghouse(s) shall be started and remain in operation during production.

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

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

f. Holly Refining and Marketing Company

i. Source-wide PM_{10} Cap

[~~By n~~]No later than January 1, 2019, PM_{10} emissions from all sources shall not exceed 0.416 tons per day (tpd).

A. Setting of emission factors:

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

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

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

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

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

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

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

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

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

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

Total 24-hour PM_{10} emissions for the emission points shall be calculated by adding the daily results of the PM_{10} emissions equations listed below for natural

gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers and wet scrubbers to arrive at a combined daily PM_{10} emission total.

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

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

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

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

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

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

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

ii. Source-wide NO_x Cap

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

A. Setting of emission factors:

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

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

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

All fuel oil combustion: 120 lbs/Kgal

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

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

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

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

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

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

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

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

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

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

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

iii. Source-wide SO_2 Cap

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

A. Setting of emission factors:

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

Natural gas - 0.60 lb SO_2/MMscf

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

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

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

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

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

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

The equations used to determine emissions are:

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

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

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

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

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

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

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

iv. Emergency and Standby Equipment

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

g. Kennecott Utah Copper (KUC): Mine

i. Bingham Canyon Mine (BCM)

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

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

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

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

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

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

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

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

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

D. Implementation Schedule

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

ii. Copperton Concentrator (CC)

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

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

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

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

i. Utah Power Plant

A. Boilers #1, #2, and #3 shall cease operations permanently upon commencing operations of Unit #5 (combined-cycle, natural gas-fired combustion turbine).

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

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

III. Startup / Shutdown Limitations:

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

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

3. Definitions:

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

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

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

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

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

Pollutant	Test Frequency
I. PM_{10}	every year

1 II. NO_X every year

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

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

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

Pollutant 68°F, 29.92 in. Hg	grains/dscf	ppmdv (3% O_2)
1. PM_{10} Units #1, #2, #3 and #4		
filterable	0.004	
filterable + condensable	0.03	
2. NOx:		
Units #1, #2 and #3 (each)		336
3. NO_X		
Unit #4		336
(Unit 4 after January 1, 2018)		60

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

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

condensable	0.29	
(ii) NO_X		384

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

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

Initial compliance testing is required for Unit #4 after low NO_X burner installation. The initial test date shall be performed within 60 days after achieving the maximum heat input capacity production rate at which the affected facility will be operated and in no case later than 180 days after the initial startup of a new emission source.

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

E. The following requirements are applicable to Units #1, #2, #3, and #4 during the period March 1 to October 1 inclusive:

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

Pollutant $68^{O}F$, 29.92 in Hg	grains/dscf	ppmdv (3% O_2)
1. Units #1, #2, and #3		
(i) PM_{10} filterable	0.029	
(ii) filterable + condensable	0.29	
(iii) NO_X Units #1, #2, and #3		426.5
2. Unit #4		
(i) PM_{10} filterable	0.029	
(ii) NO_X		384

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

Pollutant	Test Frequency
1. PM_{10}	every year
2. NO_X	every year

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

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

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

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

III. KUC shall measure at least 95% of the required increments in any one month that coal is burned in Units #1, #2, #3 or #4.

ii. Tailings Impoundment

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

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

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

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

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

I. Alert the Utah Division of Air Quality promptly.

II. Continue surveillance and coordination of appropriate measures.

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

Kennecott Utah Copper (KUC): Smelter & Refinery

i. Smelter

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

I. Main Stack (Stack No. 11)

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

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

3. NO_x
   a. 154 lbs/hr (daily average)

II. Holman Boiler

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

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

Emission Point	Pollutant	Test Frequency
I. Main Stack (Stack No. 11)	PM_{10}	every year
	SO_2	CEM
	NO_x	CEM
II. Holman Boiler	NO_x	every three years & alternate method according to applicable NSPS standards

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

ii. Refinery:

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

Emission Point	Pollutant	Maximum Emission Rate
The sum of two (Tankhouse) Boilers	NO_X	9.5 lbs/hr
Combined Heat Plant	NO_X	5.96 lbs/hr

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

Emission Point	Pollutant	Testing Frequency
Tankhouse Boilers	NO_X	every three years*
Combined Heat Plant	NO_X	every year

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

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

iii. Molybdenum Autoclave Project (MAP):

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

Emission Point	Pollutant	Maximum Emission Rate
Combined Heat Plant	NO_X	5.01 lbs/hr

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

Emission Point	Pollutant	Testing Frequency
Combined Heat Plant	NO_X	every year

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

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

j. PacifiCorp Energy: Gadsby Power Plant

i. Steam Generating Unit #1:

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

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

ii. Steam Generating Unit #2:

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

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

iii. Steam Generating Unit #3:

A. Emissions of NO_x shall be no greater than

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

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

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

iv. Steam Generating Units #1-3:

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

v. Natural Gas-fired Simple Cycle Turbine Units:

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

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

vi. Combustion Turbine Startup / Shutdown Emission Minimization Plan

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

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

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

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

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

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

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

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

k. Tesoro Refining & Marketing Company

i. Source-wide PM_{10} Cap

[~~By n~~]No later than January 1, 2019, combined emissions of PM_{10} shall not exceed 2.25 tons per day (tpd).

A. Setting of emission factors:

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

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

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

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

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

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

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

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

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

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

Total 24-hour PM_{10} emissions for the emission points shall be calculated by adding the daily results of the PM_{10} emissions equations listed below for natural

gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers and wet scrubber to arrive at a combined daily PM_{10} emission total. For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

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

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

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

ii. Source-wide NO_x Cap
[~~By n~~]No later than January 1, 2019, combined emissions of NO_x shall not exceed [~~1.988~~]2.3 tons per day (tpd) and 475 tons per rolling 12-month period.

A. Setting of emission factors:

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

Natural gas/refinery fuel gas combustion using: Low NO_x burners (LNB): [~~41 lbs/MMbtu~~]0.051 lbs/MMbtu
Ultra-Low NO_x (ULNB) burners: 0.04 lbs/MMbtu
Diesel fuel: shall be determined from the latest edition of AP-42

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

Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr has already been performed and shall be conducted at least once every three (3) years following the date of the last test. At that time a new flow-weighted average emission factor in terms of: lbs/MMbtu shall be derived for each combustion type listed in IX.H.2.k.ii.A above. Stack testing shall be performed as outlined in IX.H.1.e. Stack testing is not required for natural gas/refinery fuel gas combustion equipment with a NO_x CEMS.

C. Compliance with the source-wide NO_x Cap shall be determined for each

day as follows:

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

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

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

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

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

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

iii. Source-wide SO_2 Cap

[~~By n~~]No later than January 1, 2019, combined emissions of SO_2 shall not exceed 3.[~~1~~]8 tons per day (tpd) and 300 tons per rolling 12-month period.

A. Setting of emission factors:

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

Natural gas: EF = 0.60 lb/MMscf
Propane: EF = 0.60 lb/MMscf
Diesel fuel: shall be determined from the latest edition of AP-42

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

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

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

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

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

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

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

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

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

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

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

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

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

Compliance with the daily limitations shall be determined as follows:

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

[~~i~~]v. Emergency and Standby Equipment

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

l. University of Utah: University of Utah Facilities

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

Emission Point	Pollutant	ppmdv (3% O_2 dry)
A. Boiler #3	NO_X	187
B. Boilers #4a & #4b	NO_X	9
C. Boilers #5a & #5b	NO_X	9
D. Turbine	NO_X	9
E. Turbine and WHRU Duct burner	NO_X	15

*Boiler #4 will be replaced with Boiler #4a and #4b by December 31, 2018.

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

Emission Point	Pollutant	Initial Test	Test Frequency
A. Boiler #3	NO_X	*	every year#
B. Boilers #4a & 4b	NO_X	2018	every year#
C. Boilers #5a & 5b	NO_X	2017	every year#
D. Turbine	NO_X	*	every year#
E. Turbine and WHRU Duct burner	NO_X	*	every year#

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

A compliance test shall be performed at least once every three years from the date of the last compliance test that demonstrated compliance with the emission limit(s). Compliance testing shall be performed using EPA approved test methods acceptable to the Director. The Director shall be notified, in accordance with all applicable rules, of any compliance test that is to be performed. Beginning January 2018, annual screening with a portable monitor must be conducted in those years that a compliance test is not performed. Screening with a portable monitor shall be performed in accordance with the

portable monitor manufacturer's specifications. If screening with a portable monitor indicates a potential exceedance of the concentration limit, a compliance test must be performed within 90 days of that screening. Records shall be kept on site which indicate the date, time, and results of each screening and demonstrate that the potable monitor was operated in accordance with manufacturer's specifications. .

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

m. [~~West Valley Power Holdings, LLC.: West Valley Power Plant~~] Utah Municipal Power Association: West Valley Power Plant.

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

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

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

H.4 Interim Emission Limits and Operating Practices

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

b. Petroleum Refineries:

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

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

B. Compliance Demonstrations.

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

For SO_x, the emission factors are:

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

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

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

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

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

c. Big West Oil Company

i. PM_{10} Emissions

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

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

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

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

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

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

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

ii. SO_2 Emissions

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

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

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

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

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

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

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

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

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

iii. NO_x Emissions

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

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

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

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

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

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

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

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

d. Chevron Products Company

i. PM_{10} Emissions

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

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

ii. SO_2 Emissions

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

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

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

iii. NO_x Emissions

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

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

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

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

e. Holly Refining and Marketing Company

i. PM_{10} Emissions

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

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

ii. SO_2 Emissions

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

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

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

iii. NO_x Emissions:

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

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

f. Tesoro Refining & Marketing Company

i. PM_{10} Emissions

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

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

ii. SO_2 Emissions

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

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

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

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

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

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

iii. NO_x Emissions

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

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

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

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

b. Definitions:

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

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

c. Recordkeeping and Reporting:

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

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

d. Emission Limitations:

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

   ii. All emission limitations of particulate matter (either PM_{10} and/or $PM_{2.5}$ listed in Subsections IX.H.12 and IX.H.13 include both filterable and condensable PM, unless otherwise specified in the source specific conditions listed in IX.H.12 and IX.H.13.

e. Stack Testing:

i. As applicable, stack testing to show compliance with the emission limitations for the sources in Subsection IX.H.12 and 13 shall be performed in accordance with the following:

A. Sample Location: The emission point shall be designed to conform to the requirements of
40 CFR 60, Appendix A, Method 1, or other EPA-approved testing methods acceptable to the Director. Occupational Safety and Health Administration (OSHA) approvable access shall be provided to the test location.

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

A. PM: 40 CFR 60, Appendix A, Method 5, or other EPA approved testing methods acceptable to the Director.

B. PM_{10}: 40 CFR 51, Appendix M, Methods 201a and 202, or other EPA approved testing methods acceptable to the Director. If a method other than 201a is used, the portion of the front half of the catch considered PM_{10} shall be based on information in Appendix B of
the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.

E. $PM_{2.5}$: 40 CFR 51, Appendix M, 201a and 202, or other EPA approved testing methods acceptable to the Director. The back half condensables shall be used for compliance demonstration as well as for inventory purposes. If a method other than 201a is used, the portion of the front half of the catch considered $PM_{2.5}$ shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.

F. SO_2: 40 CFR 60 Appendix A, Method 6C, or other EPA-approved testing methods acceptable to the Director.

G. NO_x: 40 CFR 60 Appendix A, Method 7E, or other EPA-approved testing methods acceptable to the Director.

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

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

J. A stack test protocol shall be provided at least 30 days prior to the test. A

pretest conference shall be held if directed by the Director.

K. The production rate during all compliance testing shall be no less than 90% of the maximum production rate achieved in the previous three (3) years. If the desired production rate is not achieved at the time of the test, the maximum production rate shall be 110% of the tested achieved rate, but not more than the maximum allowable production rate. This new allowable maximum production rate shall remain in effect until successfully tested at a higher rate. The owner/operator shall request a higher production rate when necessary. Testing at no less than 90% of the higher rate shall be conducted. A new maximum production rate (110% of the new rate) will then be allowed if the test is successful. This process may be repeated until the maximum allowable production rate is achieved.

f. Continuous Emission and Opacity Monitoring

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

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

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

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

g. Petroleum Refineries.

i. Limits at Fluid Catalytic Cracking Units

A. FCCU SO_2 Emissions

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

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

B. FCCU PM Emissions

I. [~~By no later than January 1, 2018, e~~]Each owner or operator of an FCCU shall comply with an emission limit of 1.0 pounds PM per 1000 pounds coke burned on a 3-hour average basis.

II. Compliance with this limit shall be determined by following the stack test protocol specified in 40 C.F.R. §60.106(b) to measure PM emissions on the FCCU. Each owner operator shall conduct stack tests once every five years at each FCCU.

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

ii. Limits on Refinery Fuel Gas

A. [~~By no later than January 1, 2018, a~~]All petroleum refineries in or affecting any $PM_{2.5}$ nonattainment area or any PM_{10} nonattainment or maintenance area shall reduce the H_2S content of the refinery plant gas to 60 ppm or less as described in 40 CFR 60.102a. Compliance shall be based on a rolling average of 365 days. The owner/operator shall comply with the fuel gas monitoring requirements of 40 CFR 60.107a and the related recordkeeping and reporting requirements of 40 CFR 60.108a. As used herein, refinery "plant gas" shall have the meaning of "fuel gas" as defined in 40 CFR 60.101a, and may be used interchangeably.

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

iii. Limits on Heat Exchangers

A. Each owner or operator shall comply with the requirements of 40 CFR 63.654 for heat exchange systems in VOC service as soon as practicable but no later than January 1, 2015. The owner or operator may elect to use another EPA-approved method other than the Modified El Paso Method if approved by the Director.

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

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

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

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

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

iv. Leak Detection and Repair Requirements

A. Each owner or operator shall comply with the requirements of 40 CFR 60.590a to 60.593a as soon as practicable[~~ but no later than January 1, 2016~~].

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

v. Requirements on Hydrocarbon Flares

A. [~~Beginning January 1, 2018, a~~]All hydrocarbon flares at petroleum refineries located in or affecting a designated $PM_{2.5}$ non-attainment area within the State shall be subject to the flaring requirements of NSPS Subpart Ja (40 CFR 60.100a–109a), if not already subject under the flare applicability provisions of Ja.

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

vi. Requirements on Tank Degassing

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

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

degassing equipment.

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

I. Start date and time;

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

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

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

V. Description of vapor control device.

vii. No Burning of Liquid Fuel Oil in Stationary Sources

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

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

h. Catalytic Oxidation for VOC Control

i. Internal Combustion Engines

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

ii. Natural Gas Combustion Turbines

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

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

a. ATK Launch Systems Inc. Promontory

i. During the period November 1 to February 28/29 on days when the 24-hour average PM2.5 levels exceed 35 ug/m3at the nearest real-time monitoring station, the open burning of reactive wastes with properties identified in 40 CFR 261.23 (a) (6) (7) (8) will be limited to 50 percent of the treatment facility's Department of Solid and Hazardous Waste permitted daily limit. During this period, on days when open burning occurs, records will be maintained identifying the quantity burned and the PM2.5 level at the nearest real-time monitoring station.

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

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

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

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

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

iii. Natural Gas-Fired Boilers

A. Building M-576

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

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

B. <u>Building M-14</u>

I. <u>One 25 MMBTU/hr boiler shall be upgraded with low NO_x burners and flue gas</u>

recirculation by December 2019. The boiler shall be rated at a maximum of 15 ppm.

b. Big West Oil Refinery

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

A. Setting of emission factors:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ii. Source-wide NO_x Cap

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

A. Setting of emission factors:

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

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

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

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

such time as stack testing is conducted as outlined below:

Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment above 40 MMBtu/hr has been performed and the next stack test shall be performed within 3 years of the previous stack test. At that time a new flow-weighted average emission factor in terms of: lbs/MMbtu shall be derived for each combustion type listed in IX.H.12.b.ii.A above. Stack testing shall be performed as outlined in IX.H.11.e.

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

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

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

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

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

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

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

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

iii. Source-wide SO_2 Cap

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

A. Setting of emission factors:

The emission factors derived from the most current performance test shall be

applied to the relevant quantities of fuel combusted. The default emission factors to be used are as follows:

Natural Gas - 0.60 lb SO_2/MMscf gas

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

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

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

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

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

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

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

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

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

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

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

fuel oil is burned), and the calculated emissions.

iv. Emergency and Standby Equipment

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

v. Alternate Startup and Shutdown Requirements

A. During any day which includes startup or shutdown of the FCCU, combined emissions of SO_2 shall not exceed 1.2 tons per day (tpd). For purposes of this subsection, a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight.

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

vi. Requirements on Hydrocarbon Flares

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

[~~c. Bountiful City Light and Power: Power Plant~~

~~i. Emissions to the atmosphere shall not exceed the following rates and concentrations:~~

~~A. GT #1 (5.3 MW Turbine) Exhaust Stack:~~
~~NO_x 0.6 g/kW-hr~~

~~B. GT #2 and GT #3 (each TITAN Turbine) Catalytic-controlled Exhaust Stack:~~
~~NO_x 15 ppm~~

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

~~A. Initial stack tests have been performed. Each turbine shall be tested at least once per year.~~

~~iii. Combustion Turbine Startup / Shutdown Emission Minimization Plan~~

~~A. Startup begins when natural gas is supplied to the combustion turbine(s) with the intent of combusting the fuel to generate electricity. Startup conditions end within sixty (60) minutes of natural gas being supplied to the turbine(s).~~

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

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

[~~d. Central Valley Water Reclamation Facility: Wastewater Treatment Plant~~

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

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

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

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

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

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

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

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

[e]c. Chemical Lime Company (LHoist North America)

Lime Production Kiln

i. No later than January 1, 2019, or upon source start-up, whichever comes later, SNCR technology shall be installed on the Lime Production Kiln[~~ for reduction of NO_x emission~~].

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

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

ii. No later than January 1, 2019, or upon source start-up, whichever comes later, a baghouse control technology shall be installed and operating on the Lime Production Kiln[~~ for reduction of PM emissions~~].

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

b. Effective January 1, 2019, or upon source start-up, whichever comes later, $PM_{2.5}$ emissions shall not exceed 1.5 lbs/ton of stone feed.

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

iii. An initial compliance test is required no later than January 1, 2019 (if start-up occurs on or before January 1, 2019) or within 180 days of source start-up (if start-up occurs after January 1, 2019)

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

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

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

b. No ammonia or urea injection during shutdown.

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

[~~f~~]d. Chevron Products Company - Salt Lake Refinery

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

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

A. Setting of emission factors:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ii. Source-wide NO_x Cap

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

A. Setting of emission factors:

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

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

Plant gas: assumed equal to natural gas

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

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

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

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

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

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

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

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

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

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

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

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

iii. Source-wide SO_2

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

A. Setting of emission factors:

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

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

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

Natural gas: EF = 0.60 lb/MMscf

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

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

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

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

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

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

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

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

iv. Emergency and Standby Equipment and Alternative Fuels

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

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

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

v. Compressor Engine Requirements

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

Engine Number	NO_x in ppmvd @ 0% O_2
1	236
2	208
3	230

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

vi. Flare Calculation

A. Chevron's Flare #3 receives gases from its Isomerization unit, Reformer unit as

well as its HF Alkylation Unit. The HF Alkylation Unit's flow contribution to Flare #3 will not be included in determining compliance with the flow restrictions set in IX.H.11.g.v.B

[~~g~~]e. Compass Minerals Ogden Inc.

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

Emission Points	Concentration (ppm)	lb/hr
Boiler #1	[~~9.0~~]12	1.6
Boiler #2	[~~9.0~~]12	1.6

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

ii. $PM_{2.5}$ emissions (filterable+condensable) to the atmosphere from each of the following emission points shall not exceed [~~a concentration of 0.01 grains/dscf (@ 68 degrees F and 29.92 in Hg)~~the listed lb/hr emission rates]:

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

Emission Unit	$PM_{2.5}$ Emission Rate (lb/hr)
AH-500	2.52
AH-502	5.49
AH-513	2.32
BH-501	3.77
BH-1545	13.55
AH-1555	1.92
BH-1400	8.42
AH-692	0.44

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

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

iii. $PM_{2.5}$ emissions (filterable only) to the atmosphere [~~from the indicated emission point shall not exceed the following rates and concentrations~~]from each of the following emission points shall not exceed the listed lb/hr emission rates:

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

~~Salt Plant Dust Collection 0.01~~]

Emission Unit	$PM_{2.5}$ Emission Rate (lb/hr)
SOP Plant Compaction Building Baghouse	0.21
BH-001	0.27
BH-002	0.6
BH-502	0.15

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

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

iv. Emissions of VOC from all Magnesium Chloride Evaporators (four stacks total) shall not exceed 9.27 lb/hr.

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

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

[~~h~~]f. Hexel Corporation: Salt Lake Operations

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

A. 5.50 MMscf of natural gas consumed per day.

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

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

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

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

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

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

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

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

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

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

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

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

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

Residence times shall be determined by:

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

Where
R = residence time
V = interior volume of the incinerator – ft3
Qmax = maximum exhaust gas flow rate – ft3/second

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ii. Source-wide NO_x Cap

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

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

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

Natural gas/refinery fuel gas combustion using:
Low NO_x burners (LNB): 41 lbs/MMscf
Ultra-Low NO_x (ULNB) burners: 0.04 lbs/MMbtu
Next Generation Ultra Low NO_x burners (NGULNB): 0.10 lbs/MMbtu
Boiler #5: 0.02 lbs/MMbtu
All other boilers with selective catalytic reduction (SCR): 0.02 lbs/MMbtu
All other combustion burners: 100 lb/MMscf

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

All fuel oil combustion: 120 lbs/Kgal

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

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

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

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

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

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

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

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

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

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

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

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

Natural gas - 0.60 lb SO_2/MMscf

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

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

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

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

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

The equations used to determine emissions are:

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

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

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

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

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

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

iv. Emergency and Standby Equipment

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

j. Kennecott Utah Copper (KUC): Mine

i. Bingham Canyon Mine (BCM)

A. [~~Maximum total mileage per calendar day for ore and waste haul trucks~~] Emissions at the Bingham Canyon Mine shall not exceed 6,205 tons of NO_x, $PM_{2.5}$, and SO_2 combined per rolling 12-month period[~~30,000 miles~~].

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

B. Maximum total NO_2 emissions from ore and waste haul trucks shall not exceed 16.9 tons per day (calendar month average).

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

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

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

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

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

[~~C~~]D. [~~To minimize emissions at the mine, the owner/operator shall:~~]The In-pit crusher baghouse shall not exceed a $PM_{2.5}$ emission limit of 0.78 lbs/hr. $PM_{2.5}$ monitoring shall be performed by stack testing every three years.

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

[~~D~~]E. Implementation Schedule

When KUC replaces[~~shall purchase new~~] haul trucks, they shall be replaced with trucks that have the highest engine Tier level available which meet mining needs. KUC shall maintain records of haul trucks purchased and [~~retired~~]replaced.

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

ii. Copperton Concentrator (CC)

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

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

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

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

B. The eight (8) Tioga heaters shall not consume more than 120 MMCF of natural gas per year.

k. Kennecott Utah Copper (KUC): Power Plant

i. Utah Power Plant

A. [~~Boilers #1, #2, and #3 shall not be operated after January 1, 2018, or upon commencing operations of Unit #5 (combined-cycle, natural gas-fired combustion turbine), whichever is sooner.~~]When burning natural gas, Unit #4 shall not exceed the following emission rates to the atmosphere:

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

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

[~~III. NH_4 2.0*~~]

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

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

* Except during startup and shutdown.

IV. Startup / Shutdown Limitations:

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

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

3. Definitions:

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

(ii) Shutdown duration cycle begins with the initiation of boiler shutdown and ends when fuel flow to the boiler is discontinued.

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

* Initial compliance testing for the [~~natural gas-fired~~]Unit 4 boiler is required. Initial testing shall be performed when burning natural gas and also when burning coal as fuel. The initial test [~~date~~]shall be performed within 60 days after achieving the maximum heat input capacity production rate at which the affected facility will be operated and in no case later than 180 days after the initial startup of a new emission source.

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

Pollutant		Test Frequency
I.	$PM_{2.5}$	every year
II.	NO_x	every year
[~~III.~~	~~NH_4~~	~~every year~~]

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

~~I. Only natural gas shall only be used as a fuel, unless the supplier or transporter of natural gas imposes a curtailment. The power plant may then burn coal, only for the duration of the curtailment plus sufficient time to empty the coal bins following the curtailment. The Director shall be notified of the curtailment within 48 hours of when it begins and within 48 hours of when it ends.~~

~~II. When burning natural gas the emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:~~]Unit #5 (combined cycle, natural gas-fired combustion turbine) shall not exceed the following emission rates to the atmosphere:

Pollutant	lbs/hr	lbs/event	ppmdv (15% O_2 dry)
I. $PM_{2.5}$ with duct firing:			
Filterable + condensable	18.8		
II. VOC:			2.0*
III. NO_x:			2.0*
Startup / Shutdown	395		
[~~IV. NH_4~~			~~2.0*~~]

* Except during startup and shutdown.

IV. Startup / Shutdown Limitations:

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

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

3. Definitions:

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

(ii) Shutdown duration cycle begins with the initiation of boiler shutdown and ends when fuel flow to the boiler is discontinued.

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

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

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

Pollutant		Test Frequency
I.	$PM_{2.5}$	every year
II.	NO_x	every year
III.	VOC	every year
[~~IV.~~	~~NH_4~~	~~every year~~]

l. Kennecott Utah Copper: Smelter and Refinery

i. Smelter:

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

I. Main Stack (Stack No. 11)

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

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

3. NO_x 154 lbs/hr (daily average)

II. Holman Boiler

1. NO_x
   a. [~~14~~]9.0 lbs/hr, (calendar-day average)

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

EMISSION POINT	POLLUTANT	TEST FREQUENCY
I. Main Stack (Stack No. 11)	$PM_{2.5}$	Every Year
	SO_2	CEM
	NO_x	CEM
II. Holman Boiler	NO_x	Every three years and alternate method according to applicable NSPS standards

The Holman boiler shall use an EPA approved test method every three years and in between years use an alternate method according to applicable NSPS standards.

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

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

ii. Refinery:

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

EMISSION POINT	POLLUTANT	MAXIMUM EMISSION RATE
The sum of two (Tankhouse) Boilers	NO_x	9.5 lbs/hr (before December 2020)
(Upgraded Tankhouse Boiler)	NO_x	1.5 lbs/hr (After December 2020)
Combined Heat Plant	NO_x	5.96 lbs/hr

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

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

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

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

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

m. Nucor Steel Mills

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

A. Electric Arc Furnace Baghouse

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

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

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

IV. VOC 22.20 lbs/hr

B. Reheat Furnace #1
NO_x 15.0 lb/hr

C. Reheat Furnace #2
NO_x 8.0 lb/hr

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

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

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

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

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

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

[~~n. Olympia Sales Company: Cabinet Manufacturing Facility~~

~~i. By July 31, 2018, a baghouse control device shall be in operation for control of the process exhaust streams from the Mill, Door, and Sanding areas.~~

~~ii. Process emissions from the Mill, Door, and Sanding areas shall be exhausted through the baghouse during startup, shutdown, and operations of the plant.~~

~~iii. The baghouse shall operate a maximum of 4,160 hours per rolling 12-month period. Records of baghouse operation shall be kept for all periods of plant operation. The records shall be kept on a daily basis. Hours of operation shall be determined by supervisor monitoring and maintaining of an operations log.~~

~~iv. The owner/operator shall comply with all applicable provisions of R307-349.~~]

n. PacifiCorp Energy: Gadsby Power Plant

i. Steam Generating Unit #1:

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

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

ii. Steam Generating Unit #2:

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

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

iii. Steam Generating Unit #3:

A. Emissions of NO_x shall be no greater than

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

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

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

iv. Steam Generating Units #1-3:

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

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

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

B. The owner/operator shall install, certify, maintain, operate, and quality-assure a CEM consisting of NO_x and O_2 monitors to determine compliance with the

NO_x limitation. The CEM shall operate as outlined in IX.H.11.f.

vi. Combustion Turbine Startup / Shutdown Emission Minimization Plan

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

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

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

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

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

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

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

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

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

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

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

A. Setting of emission factors:

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

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

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

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

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

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

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

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

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

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

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

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

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

ii. Source-wide NO_x Cap

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

A. Setting of emission factors:

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

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

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

Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr has already been performed and shall be conducted at least once every three (3) years following the date of the last test. At that time a new flow-weighted average emission factor in terms of: lbs/MMbtu shall be derived for each combustion type listed in IX.H.12.p.ii.A above. Stack testing shall be performed as outlined in IX.H.11.e. Stack testing is not required for natural gas/refinery fuel gas combustion equipment with a NO_x CEMS.

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

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

IX.H.11.f.

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

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

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

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

iii. Source-wide SO_2 Cap

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

A. Setting of emission factors:

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

Natural gas: EF = 0.60 lb/MMscf
Propane: EF = 0.60 lb/MMscf
Diesel fuel: shall be determined from the latest edition of AP-42

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

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

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

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

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

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

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

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

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

C. Instead of complying with Condition IX.H.11.g.ii.A, [~~By no later than January 1, 2018,~~]source may reduce the H_2S content of the refinery plant gas to 60 ppm or less or reduce SO_2 concentration from fuel gas combustion devices to 8 ppmvd at 0% O_2 or less as described in 40 CFR 60.102a. Compliance shall be based on a rolling average of 365 days. The owner/operator shall comply with the fuel gas or SO_2 emissions monitoring requirements of 40 CFR 60.107a and the related recordkeeping and reporting requirements of 40 CFR 60.108a. As used herein, refinery "plant gas" shall have the meaning of "fuel gas" as defined in 40 CFR 60.101a, and may be used interchangeably.

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

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

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

Compliance with the daily limitations shall be determined as follows:

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

[~~iv~~]v. Emergency and Standby Equipment

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

p. The Procter & Gamble Paper Products Company

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

Source: Paper Making Boilers (Each)

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

Source: Paper Machine Process Stack

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

Source: Utility Boilers (Each)

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

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

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

ii. Boiler Startup/Shutdown Emissions Minimization Plan

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

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

iii. Paper Machine Startup/Shutdown Emissions Minimization Plan

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

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

q. University of Utah: University of Utah Facilities

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

Emissions Point	Pollutant	ppmdv (3% O_2 dry)
~~[Boilers #3]~~	[~~NO_x~~]	[~~18~~]7
Boiler[~~s~~] #4[~~a & 4b~~]*	NO_X	[~~9~~]7
Boilers #[~~5a~~]6 & [~~5b~~]7	NO_X	9
Boiler #9*	NO_X	9
Turbine	NO_X	9
Turbine and WHRU Duct burner	NO_X	15

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

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

Emissions Point	Pollutant	Initial Test	Test Frequency[#]
[~~Boilers #3~~]	[~~NO_x~~]	[~~*~~]	[~~every 3 years~~]
Boiler~~s~~ #4[~~a & 4b~~]*	NO_X	[~~2018~~]*	[~~every 3 years~~]#
Boilers #[~~5a~~]6 & [~~5b~~]7	NO_X	[~~2017~~]*	[~~every 3 years~~]#
Boiler #9*	NO_X	2020	[~~every 3 years~~]#
Turbine	NO_X	*	[~~every 3 years~~]#
Turbine and WHRU Duct Burner	NO_X	*	[~~every 3 years~~]#

Initial test already performed

* Initial tests have been performed and the next method test using EPA approved test methods shall be performed within 3 years of the last stack test. Initial compliance testing for Boiler #9 is required. The initial test date shall be performed within 60 days after achieving the maximum heat input capacity production rate at which the affected facility will be operated and in no case later than 180 days after the initial startup of a new emission source.

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

~~ii.~~ ~~[After January 1, 2019, Boiler #3 shall only be used as a back-up/peaking boiler and shall not exceed 300 hours of operation per rolling 12 months. Boiler #3 may be operated on a continuous basis if it is equipped with low NO_x burners or is replaced with a boiler that has low NO_x burners. The burners shall have a NO_x rating that are 9 ppm or less~~]Boiler #4 in the LCHWTP shall be decommissioned and replaced by Boiler #9 by December 31, 2019.

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

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

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

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

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

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

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

[~~u. Wasatch Integrated Waste Management District~~

~~Energy Recovery Facility~~

~~i. By January 1, 2018, SNCR technology shall be installed and operating on each of the two Municipal Waste Combustors for the reduction of NO_x emissions.~~

~~ii. By January 1, 2018, emissions of NO_x from the Municipal Waste Combustors shall not exceed 320 ppmdv (7% O_2, dry basis), based on a 24-hour daily arithmetic average concentration.~~

~~A. Compliance with the NO_x limitation shall be determined by operation of CEMS. The operation of the CEMS shall be in accordance with IX.H.11.f.~~

~~iii. Emissions of SO_2 from the Municipal Waste Combustors shall not exceed 31 ppmdv (7% O_2, dry basis), based on a 24-hour daily block geometric average concentration.~~

~~A. Compliance with the SO_2 limitation shall be determined by operation of CEMS. The operation of the CEMS shall be in accordance with IX.H.11.f.~~

~~iv. Emissions of $PM_{2.5}$ from the Municipal Waste Combustors shall not exceed 27 milligrams (filterable) per dry standard cubic meter (Averaging Time: 3-run average), based on a run duration specified in the test method.~~

~~A. Compliance with the $PM_{2.5}$ limitation shall be determined by stack testing. The stack testing shall be done in accordance with IX.H.11.e.~~

~~v. Gas Suspension Absorber (GSA) and PAC Injection~~

~~A. The control system for the GSA shall automatically shut-down or start-up the feeder screws, slurry pumps, and PAC feeder based upon minimum required gas flows and temperature.~~

~~B. The facility shall follow the Operations and Maintenance Manual shall ensure the GSA is operated as long as possible during startup/shutdown:~~

~~I. Cold Light Off~~
~~The GSA is placed into startup sequence during final heating when the ESP inlet temperature reaches 285 degrees Fahrenheit and coincident to introducing MSW to the unit.~~

~~II. Hot Light Off~~
~~The GSA is placed into startup sequence during final heating when the ESP inlet temperature reaches 285 degrees Fahrenheit and coincident to introducing MSW to the unit.~~

~~III. Secure to Hot~~
~~Continue operations of the GSA after stopping feeding of refuse until ESP inlet temperature drops below 285 degrees Fahrenheit.~~

~~IV. Secure to Cold~~

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

~~V. Malfunction Shut Down~~

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

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

~~vi. Electrostatic Precipitator (ESP)~~

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

~~I. Cold Light Off~~

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

~~II. Hot Light Off~~

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

~~III. Secure to Hot~~

~~Continue operations of the ESP throughout shutdown period as possible.~~

~~IV. Secure to Cold~~

~~Continue operations of the ESP throughout shutdown period as possible.~~

~~V. Malfunction Shut Down~~

~~Continue operations of the ESP throughout shutdown period as possible.~~

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

~~Landfill Operation~~

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

s. Hill Air Force Base

i. Painting and Depainting Operations

A. VOC emissions from painting and depainting operations shall not exceed 0.58 tons per day (tpd).

I. No later than the 28th of each month, a rolling 30-day VOC emission average shall be calculated for the previous month.

ii. Boilers

A. The combined NO_x emissions for all boilers (except those less than 5 MMBtu/hr) shall not exceed 95 lb/hr. This limit shall not apply during periods of curtailment.

I. No later than the 28th of each month, the NO_x lb/hr emission total shall be calculated for the previous month.

B. No later than December 31, 2024, no boiler shall be operating on base with the capacity over 30 MMBtu/hr and with a manufacture date older than January 1, 1989.

ITEM 9

State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-035-18

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

FROM: Thomas Gunter, Environmental Planning Consultant

DATE: May 24, 2018

SUBJECT: PROPOSE FOR PUBLIC COMMENT: Amend R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits.

The amendments to Section IX, Control Measures for Area and Point Sources, Part H, for Emission Limits will have to be incorporated into the Utah Air Quality Rules. R307-110-17 is the rule that incorporates the new amendments to Part H into the rules. If the Board adopts the amendments proposed to Part H, these amendments will become part of Utah's State Implementation Plan when the rule is finalized.

Recommendation: Staff recommends the Board propose R307-110-17 for public comment.

195 North 1950 West • Salt Lake City, Utah
Mailing Address: P.O. Box 144820 • Salt Lake City, Utah 84114-4820
Telephone (801) 536-4000 • Fax (801) 536-4099 • T.D.D. (801) 536-4284
www.deq.utah.gov

Appendix 1: Regulatory Impact Summary Table*

Fiscal Costs	FY 2019	FY 2020	FY 2021
State Government	$5,710,600	$0	$0
Local Government	$0	$0	$0
Small Businesses	$0	$0	$0
Non-Small Businesses	$79,770,250	$0	$0
Other Person	$0	$0	$0
Total Fiscal Costs:	**$85,480,850**	**$0**	**$0**
Fiscal Benefits			
State Government	$0	$0	$0
Local Government	$0	$0	$0
Small Businesses	$0	$0	$0
Non-Small Businesses	$0	$0	$0
Other Persons	$0	$0	$0
Total Fiscal Benefits:	**$0**	**$0**	**$0**
Net Fiscal Benefits:	-$85,480,850	$0	$0

***This table only includes fiscal impacts that could be measured. If there are inestimable fiscal impacts, they will not be included in this table. Inestimable impacts for State Government, Local Government, Small Businesses and Other Persons are described in the narrative. Inestimable impacts for Non-Small Businesses are described in Appendix 2.**

Appendix 2: Regulatory Impact to Non-Small Businesses

For a complete listing of NAICS codes used in this analysis, please contact the agency. There are ten companies operating in Utah that will incur costs necessary to comply with the amendments to the Utah State Implementation Plan, Emission Limits and Operating Practices, Section IX, Part H. These businesses will experience a fiscal cost associated with the installation or replacement of equipment that meets or exceeds Best Available Control Technology (BACT). BACT is required in serious nonattainment areas by Federal law. Although the entirety of the fiscal impact is reported in 2019, it is possible that upgrades may take until 2024 to complete. It is the agency’s belief that a majority of upgrades or replacements will be completed by the end of 2019. The costs of upgrades or replacements vary between $233,000 and $28,200,000, depending on each company’s individual requirements.

It is possible that Local and State Governments could incur a fiscal benefit due to increase air quality and its relation the overall health of affected residents. These benefits would be a result of reductions in subsidized medical coverage to residents suffering from medical conditions connected to air quality. Any qualitative information that would provide estimates of the total benefits will

not be known until after the upgrades or replacements of equipment at industrial sites are installed. Therefore, any benefit analysis towards the local and state governments is inestimable at this time.

The Executive Director of the Department of Environmental Quality, Alan Matheson, has reviewed and approved this fiscal analysis.

****"Non-small business" means a business employing 50 or more persons; "small business" means a business employing fewer than 50 persons.**

R307. Environmental Quality, Air Quality.
R307-110. General Requirements: State Implementation Plan.

R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits.

The Utah State Implementation Plan, Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits and Operating Practices, as most recently amended by the Utah Air Quality Board on [~~December 7~~]September 5, 201[~~6~~]8, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

KEY: air pollution, PM10, PM2.5, ozone
Date of Enactment or Last Substantive Amendment: [~~December 8, 2016~~]2018
Notice of Continuation: January 27, 2017
Authorizing, and Implemented or Interpreted Law: 19-2-104

ITEM 10

Air Toxics

State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQA-440-18

M E M O R A N D U M

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: May 8, 2018

SUBJECT: Air Toxics, Lead-Based Paint, and Asbestos (ATLAS) Section Compliance Activities – April 2018

Asbestos Demolition/Renovation NESHAP Inspections	53
Asbestos AHERA Inspections	4
Asbestos State Rules Only Inspections	3
Asbestos Notification Forms Accepted	148
Asbestos Telephone Calls	464
Asbestos Individuals Certifications Approved/Disapproved	204/0
Asbestos Company Certifications/Re-Certifications	15
Asbestos Alternate Work Practices Approved/Disapproved	17/0
Lead-Based Paint (LBP) Inspections	3
LBP Notification Forms Approved	1
LBP Telephone Calls	20
LBP Letters Prepared and Mailed	8
LBP Courses Reviewed/Approved	0/0
LBP Course Audits	1
LBP Individual Certifications Approved/Disapproved	17/0
LBP Firm Certifications	17

Notices of Violation Sent	0
Compliance Advisories Sent	15
Warning Letters Sent	10
Settlement Agreements Finalized	2
Penalties Agreed to:	
Nelson Contractors	$ 2,250.00
Lonestar Builders, LLC	$ 1,250.00
Weber School District	$ 375.00
Fresh Air Environmental Solutions, Inc.	$ 703.13

Compliance

State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQC-626-18

M E M O R A N D U M

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: May 14, 2018

SUBJECT: Compliance Activities – April 2018

Annual Inspections Conducted:

Major 5
Synthetic Minor 2
Minor 26

On-Site Stack Test Audits Conducted: 4

Stack Test Report Reviews: 20

On-Site CEM Audits Conducted: 1

Emission Reports Reviewed: 16

Temporary Relocation Requests Reviewed & Approved: 8

Fugitive Dust Control Plans Reviewed & Accepted: 213

Soil Remediation Report Reviews: 2

[1]Miscellaneous Inspections Conducted: 60

Complaints Received: 15

Breakdown Reports Received: 0

195 North 1950 West • Salt Lake City, Utah
Mailing Address: P.O. Box 144820 • Salt Lake City, Utah 84114-4820
Telephone (801) 536-4000 • Fax (801)536-4099 • T.D.D. (801) 903-3978
www.deq.utah.gov

Compliance Actions Resulting from a Breakdown..... 0

Warning Letters Issued: 1

Notices of Violation Issued:..... 0

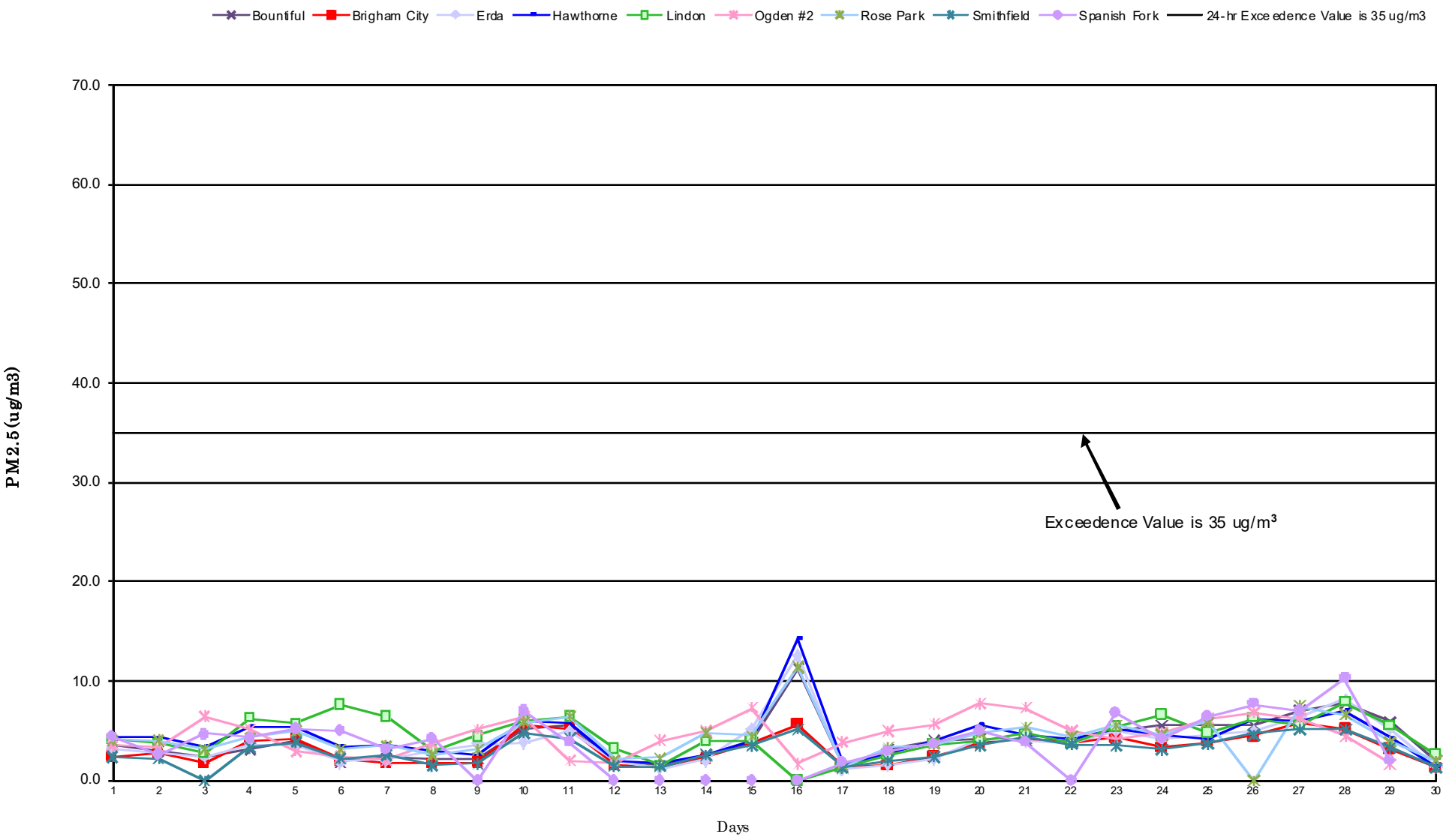
Compliance Advisories Issued:..... 2

Settlement Agreements Reached: 0

[1]Miscellaneous inspections include, e.g., surveillance, level I inspections, VOC inspections, complaints, on-site training, dust patrol, smoke patrol, open burning, etc.

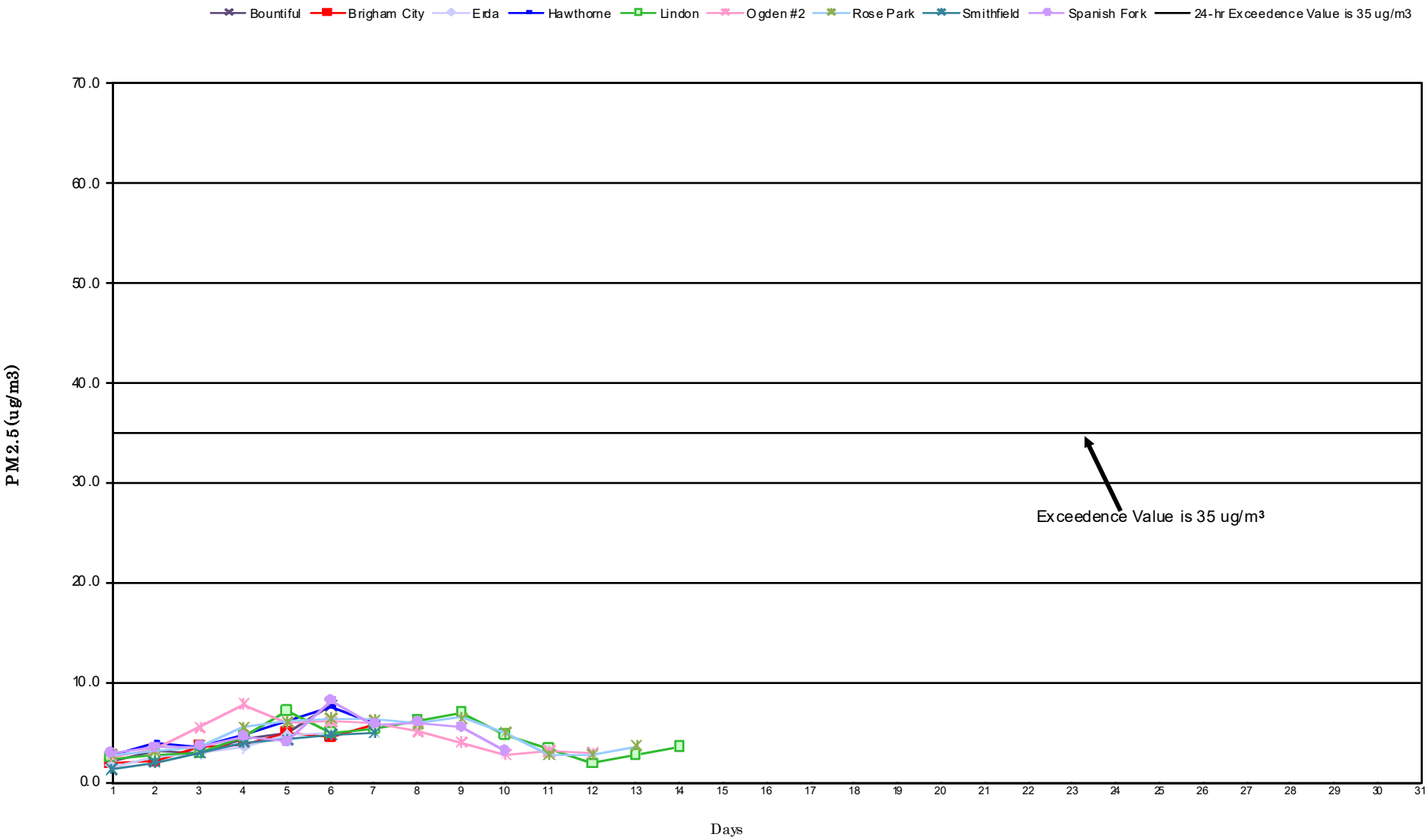
Air Monitoring

Utah 24-Hr PM2.5 Data April 2018



Utah Division of Air Quality

Utah 24-Hr PM2.5 Data May 2018



Utah Division of Air Quality

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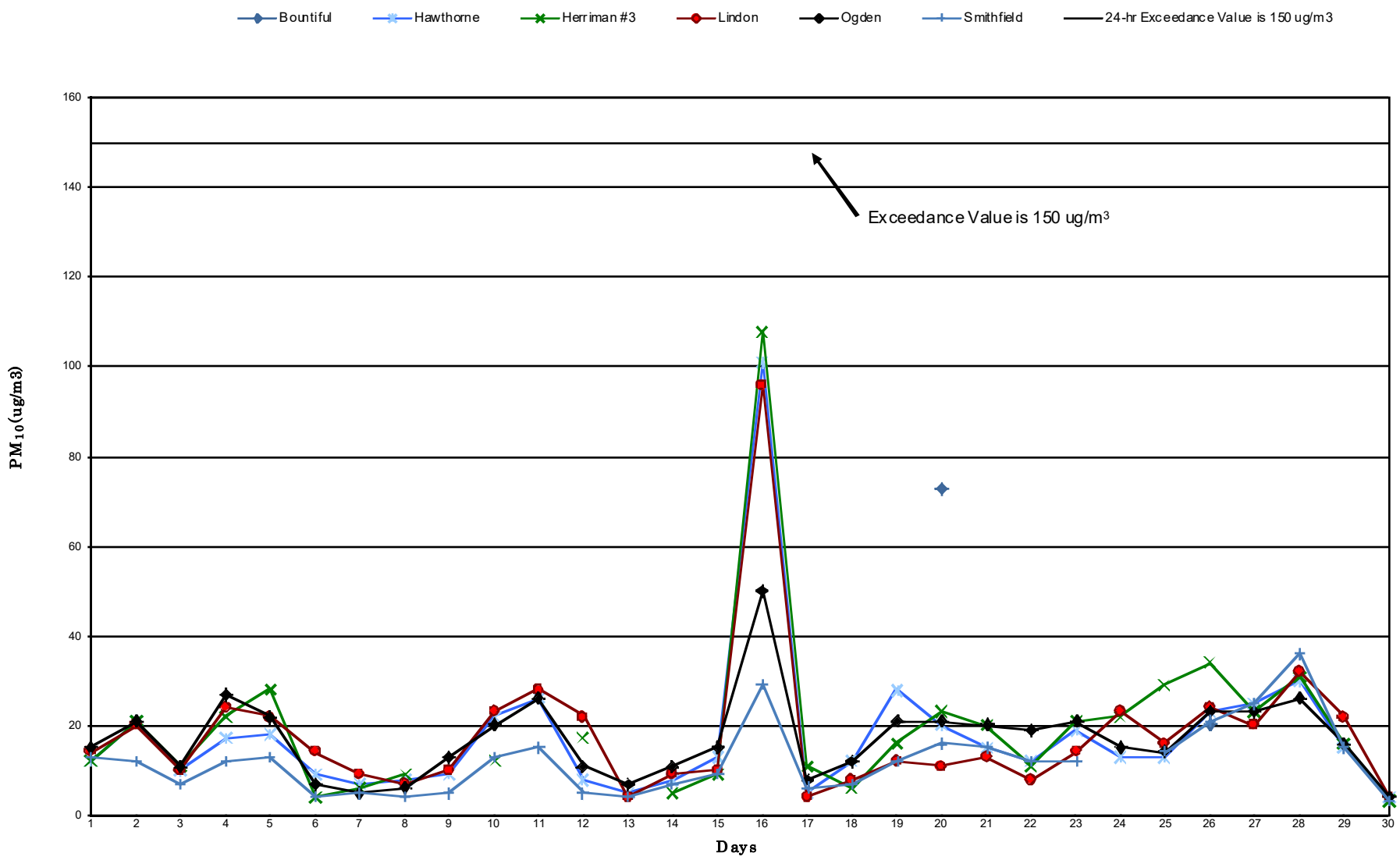
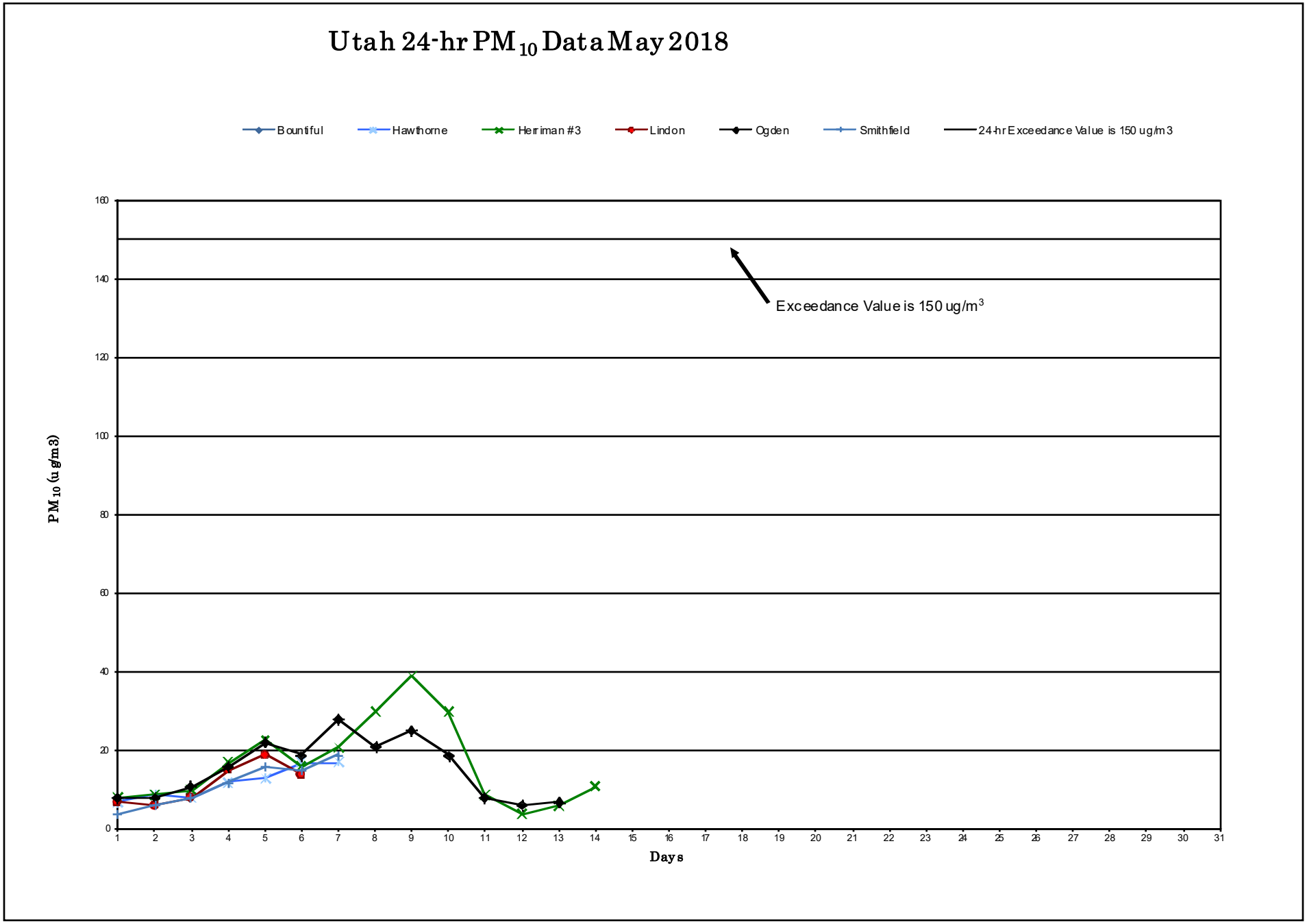
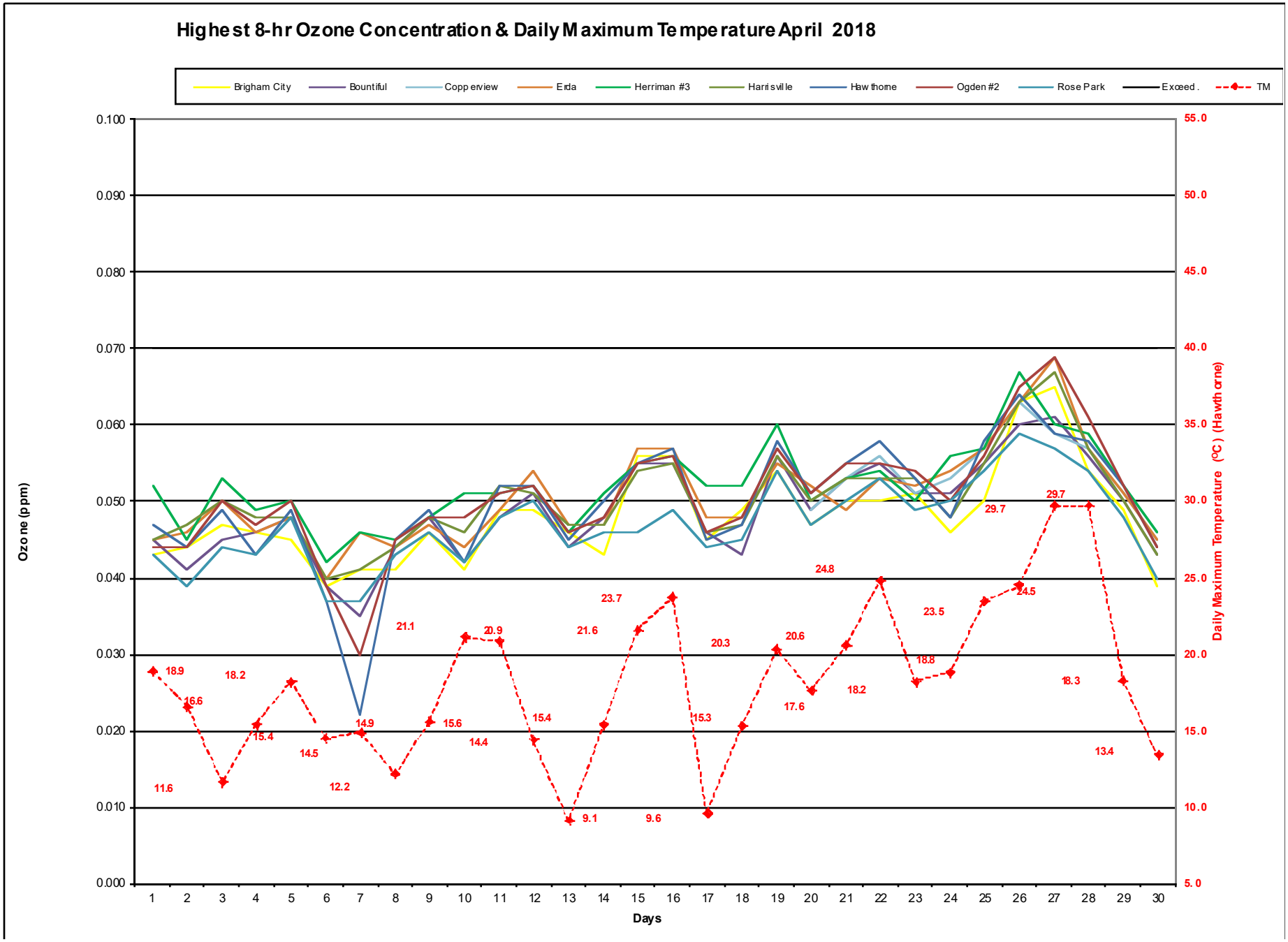




Utah Division of Air Quality


Highest 8-hr Ozone Concentration & Daily Maximum Temperature April 2018
Brigham City
Bountiful
Copperview
Erda
Herriman #3
Harrisville
Hawthorne
Ogden #2
Rose Park
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (°C) (Hawthorne)
Days
0.100
0.090
0.080
0.070
0.060
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0.040
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1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
18.9
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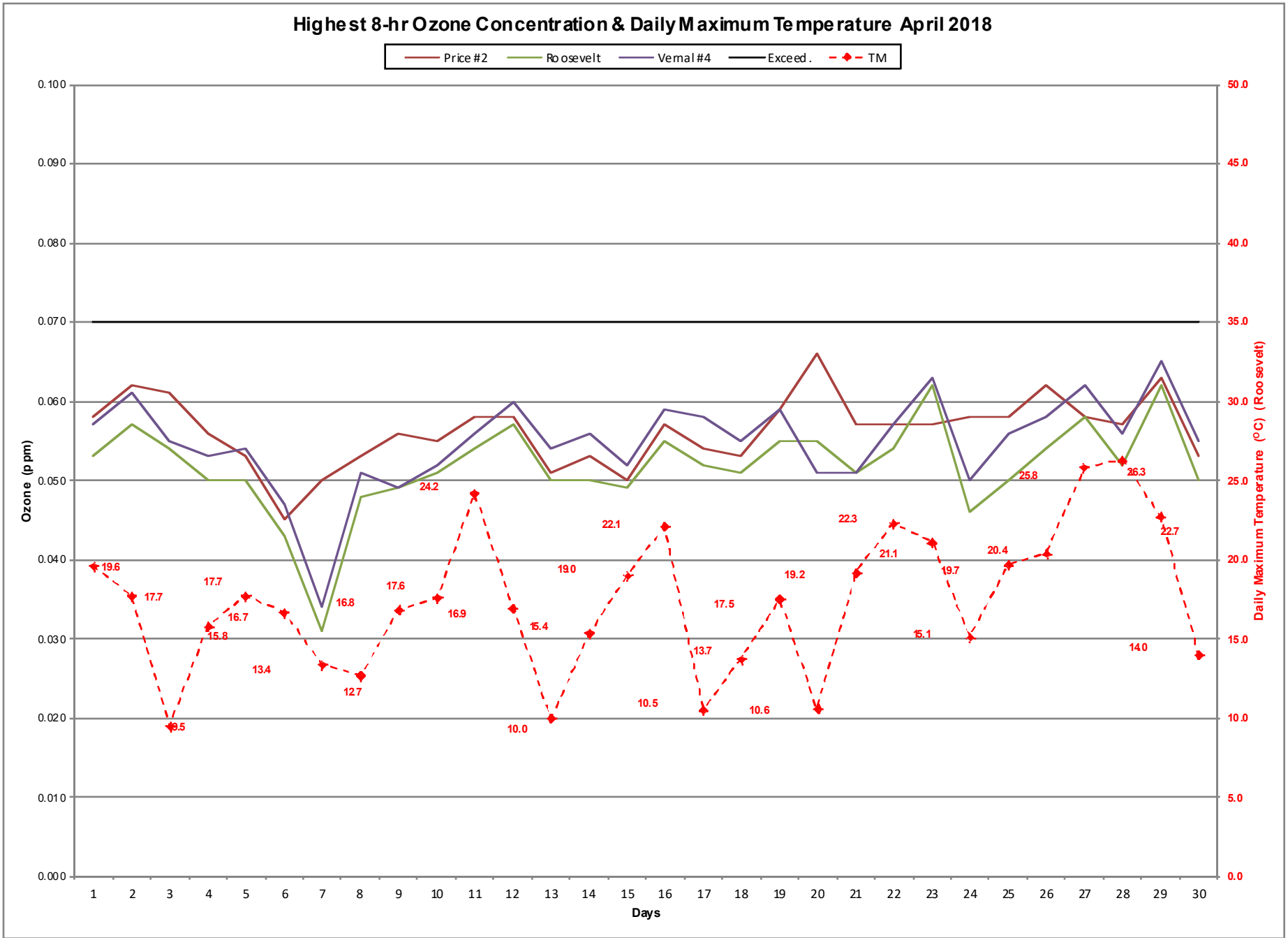
Highest 8-hr Ozone Concentration & Daily Maximum Temperature April 2018
Price #2
Roosevelt
Vernal #4
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (°C) (Roosevelt)
Days
0.100
0.090
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14.0
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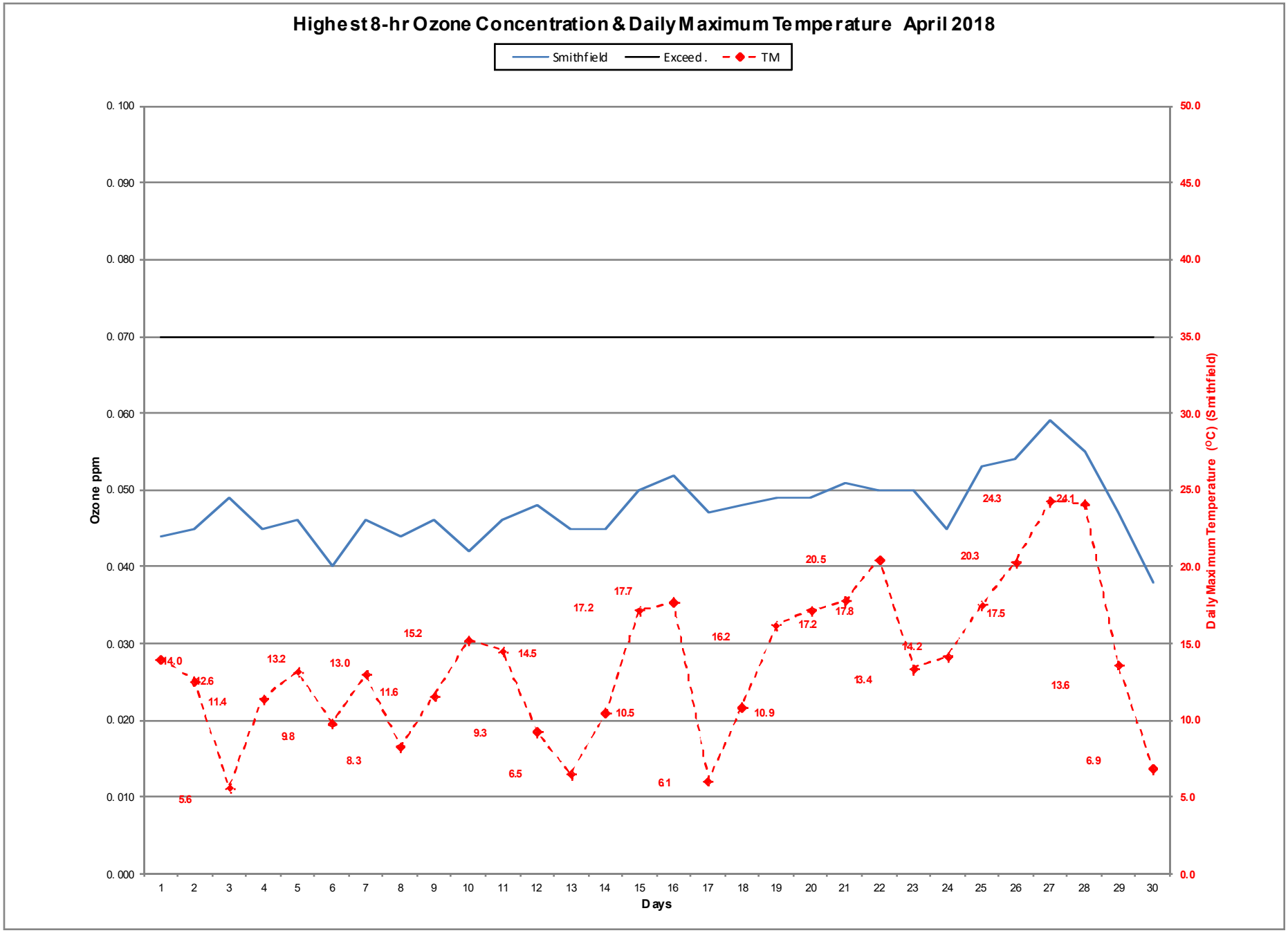
Highest 8-hr Ozone Concentration & Daily Maximum Temperature April 2018
Smithfield
Exceed.
TM
Ozone ppm
Daily Maximum Temperature (°C) (Smithfield)
Days
0.100
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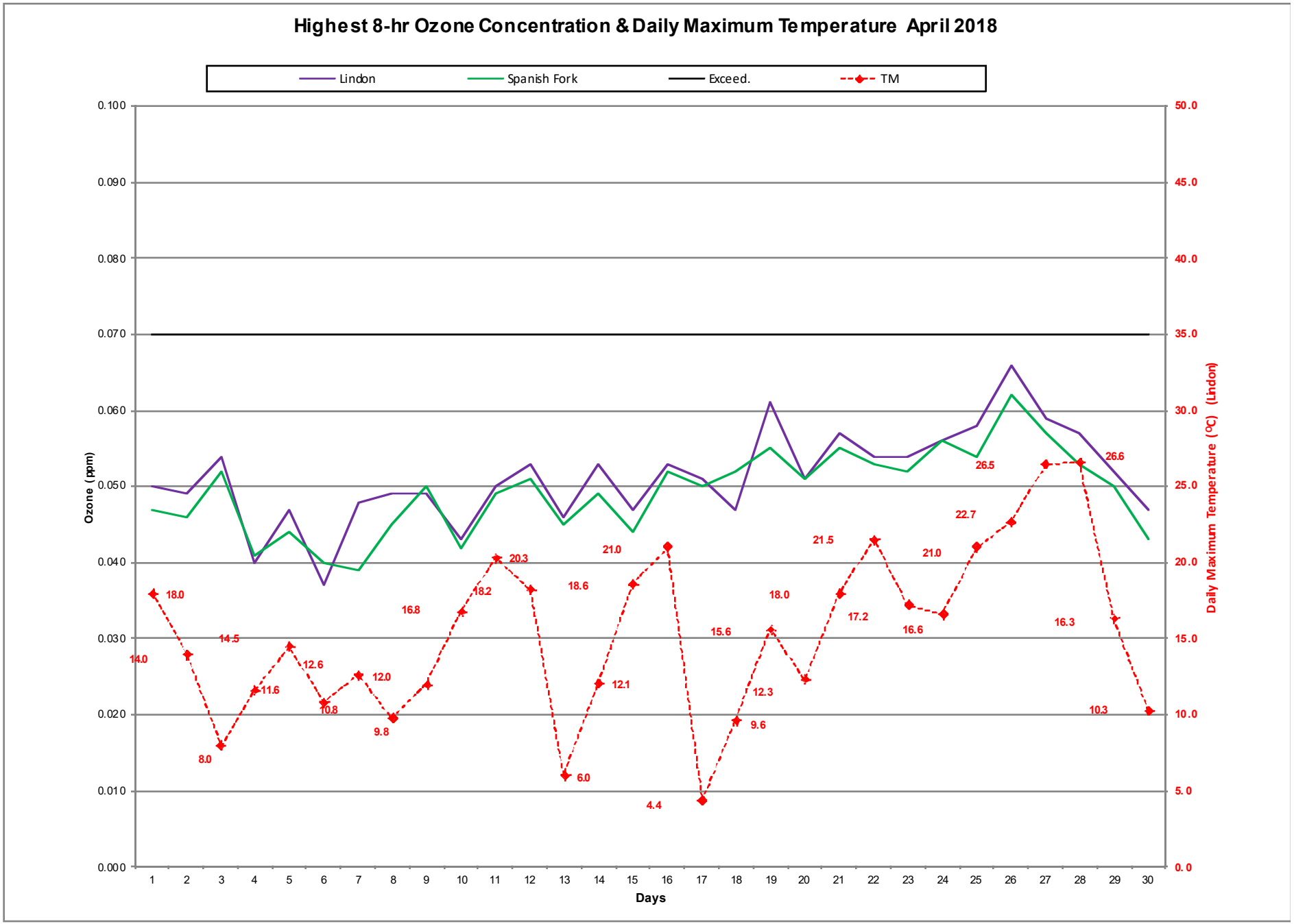
Highest 8-hr Ozone Concentration & Daily Maximum Temperature April 2018
Lindon
Spanish Fork
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (ºC) (Lindon)
Days
0.100
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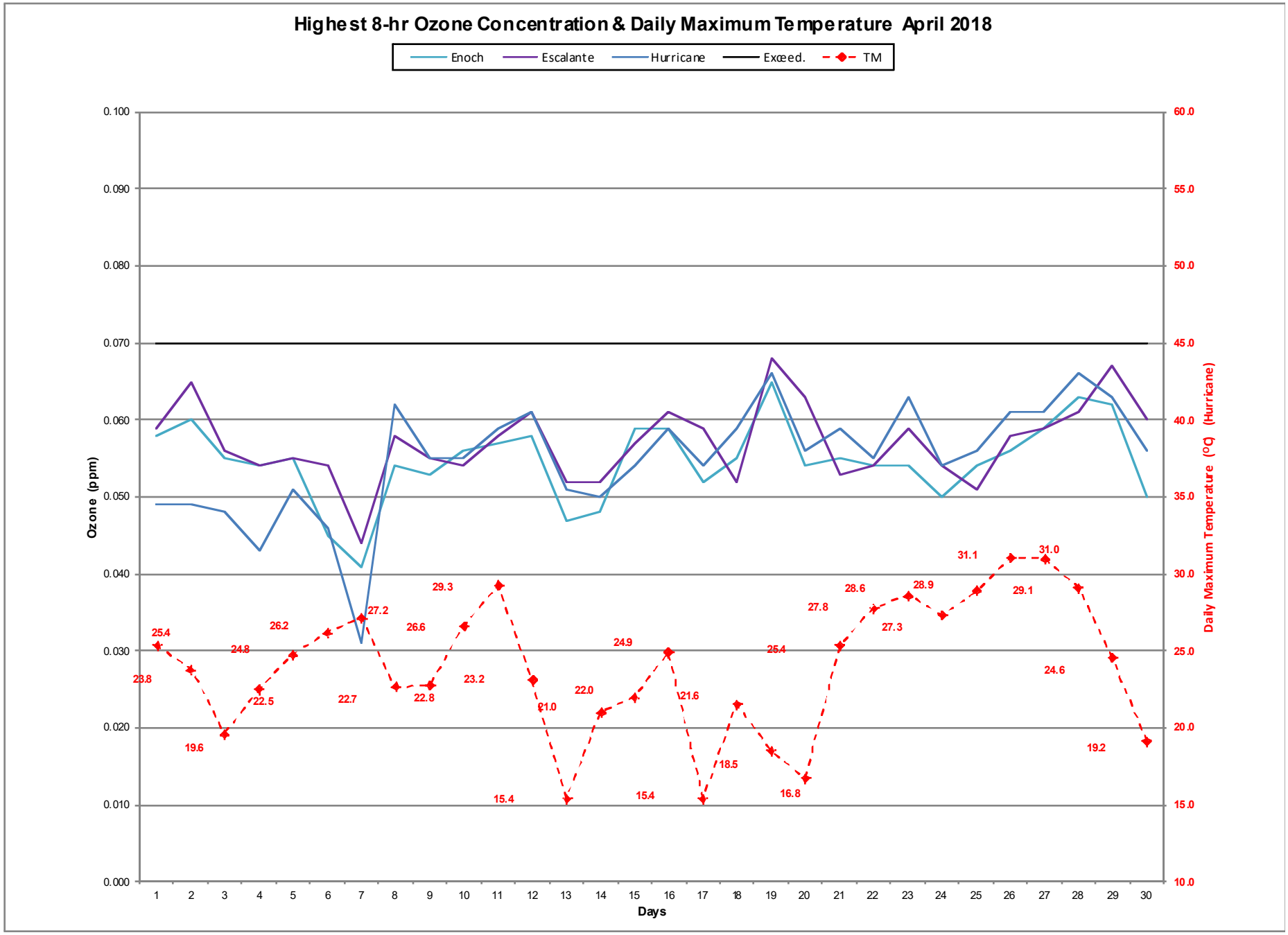
Highest 8-hr Ozone Concentration & Daily Maximum Temperature April 2018
Enoch
Escalante
Hurricane
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (°C) (Hurricane)
Days
0.100
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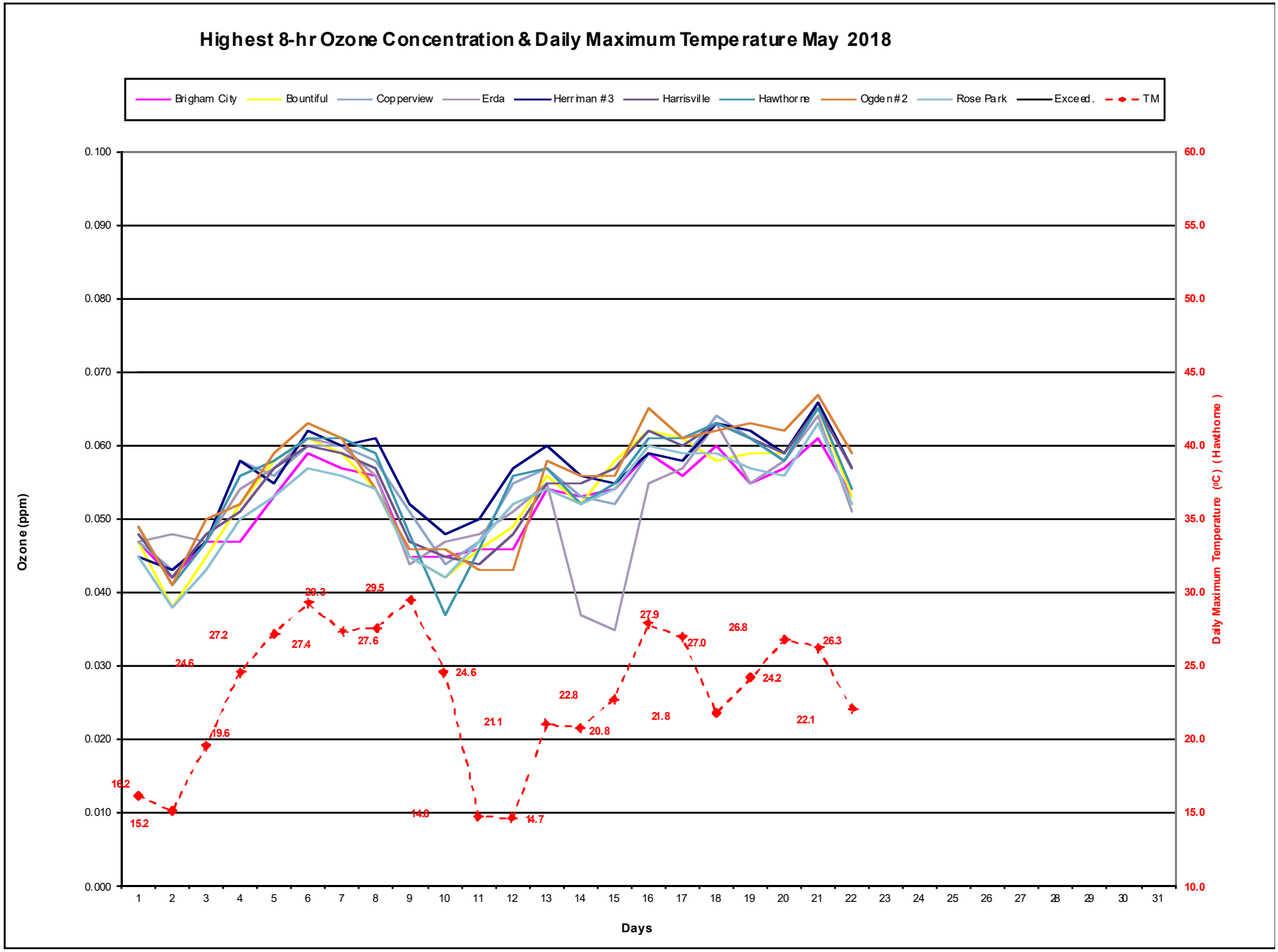
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Bountiful
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Ogden #2
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Exceed.
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Ozone (ppm)
Daily Maximum Temperature (ºC) (Hawthorne)
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0.100
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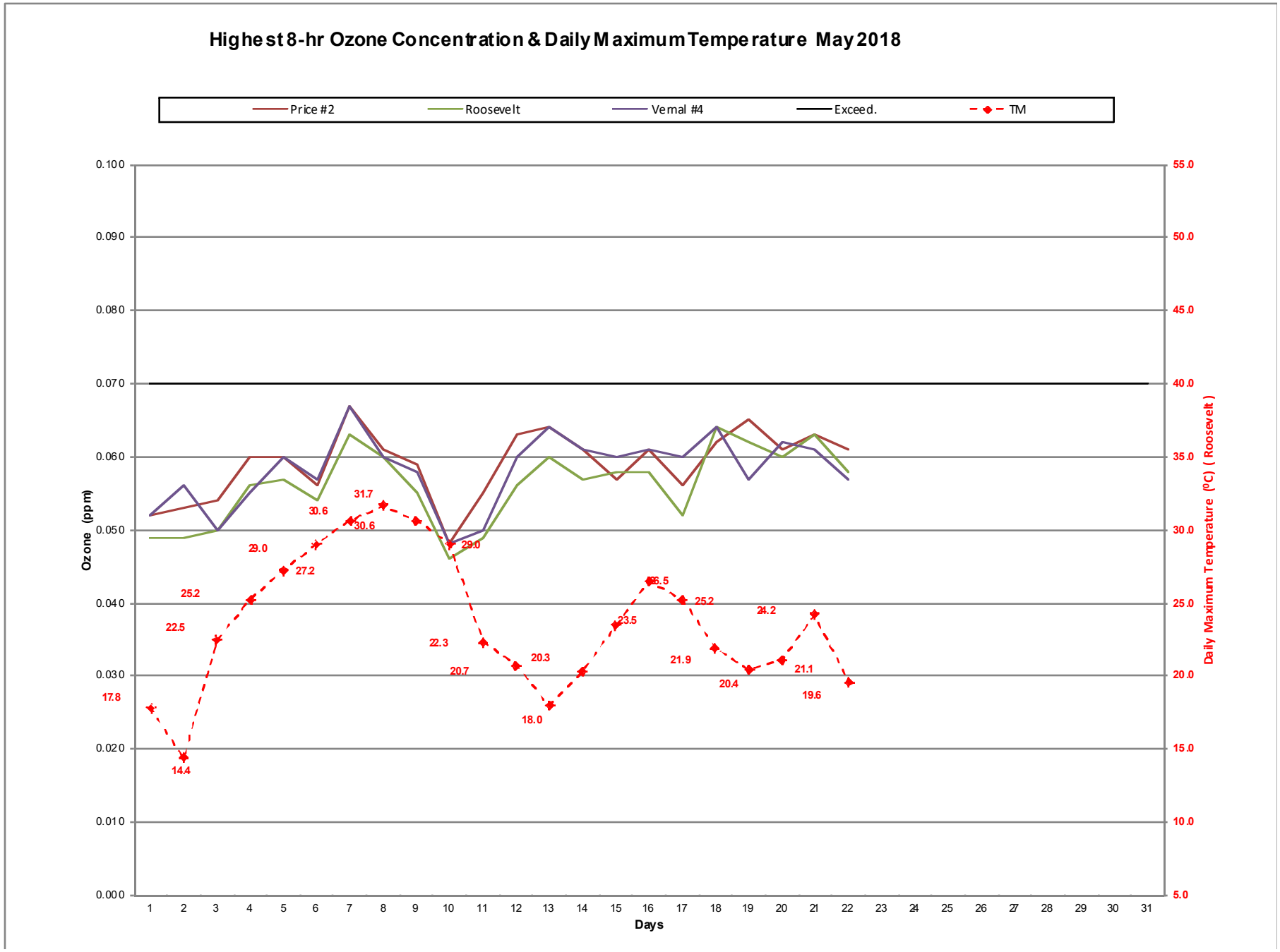
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Price #2
Roosevelt
Vernal #4
Exceed.
TM
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Daily Maximum Temperature (°C) (Roosevelt)
Days
0.100
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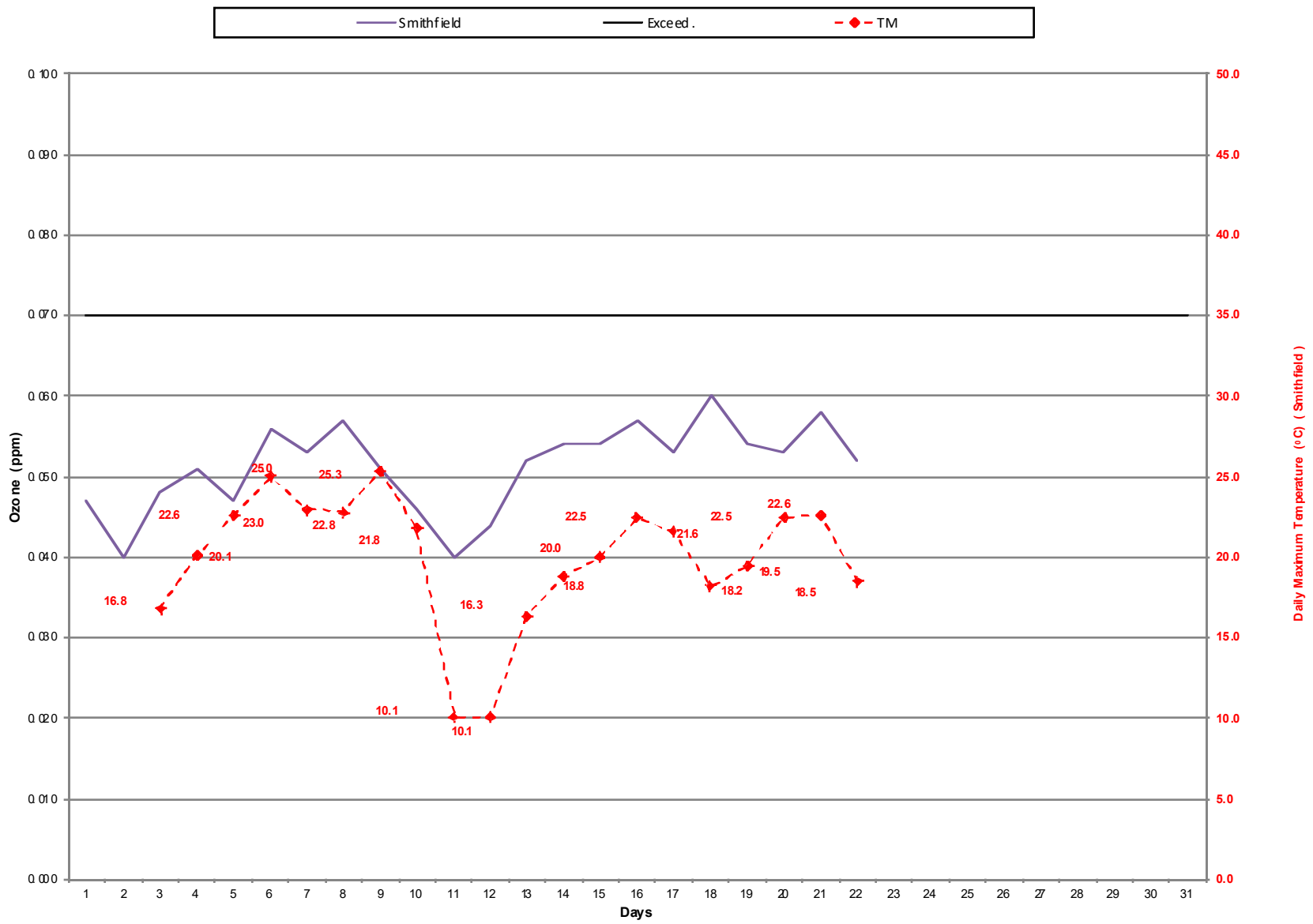
Highest 8-hr Ozone Concentration & Daily Maximum Temperature May 2018
Smithfield
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (°C) (Smithfield)
Days
0.100
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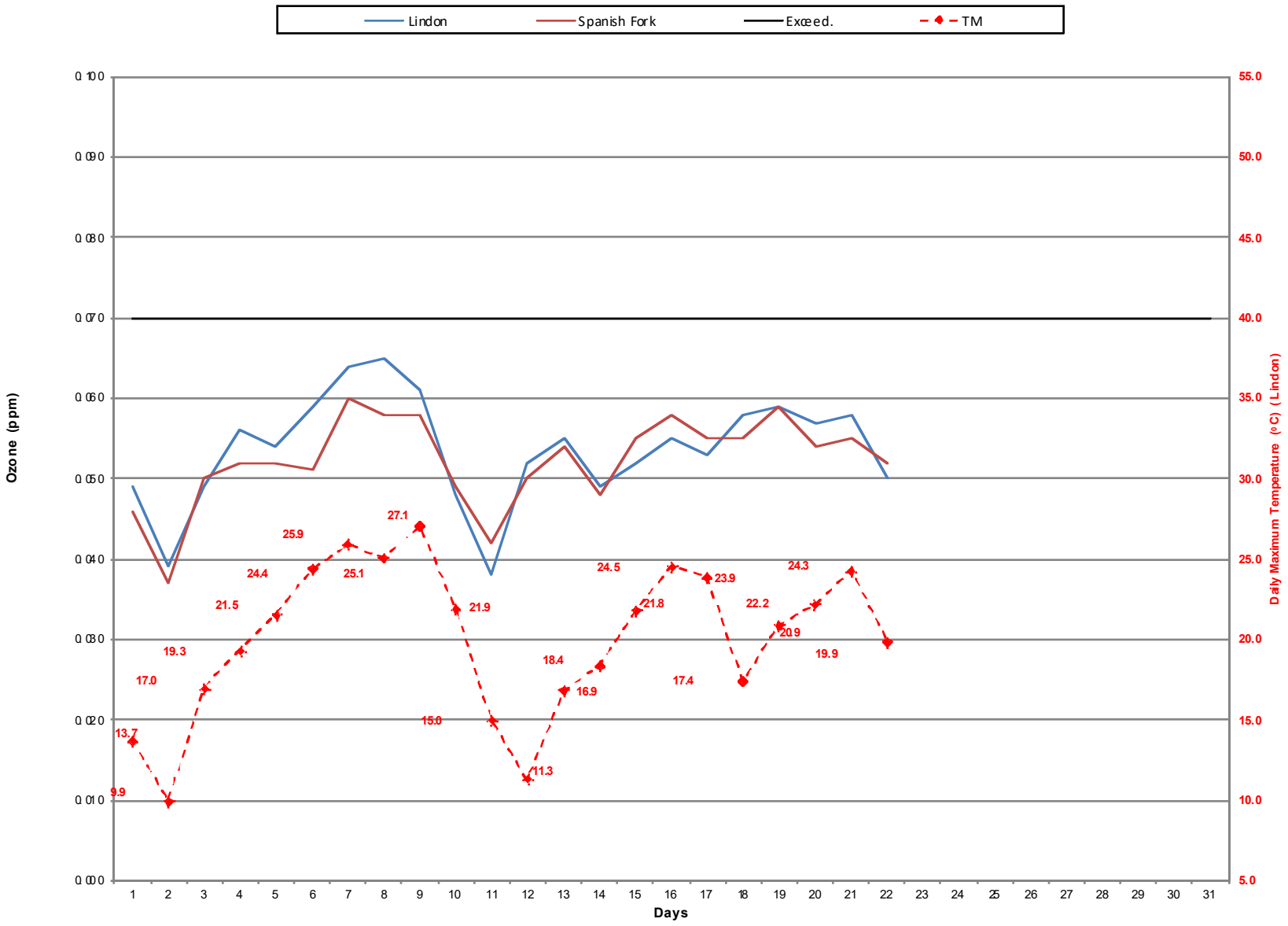
Highest 8-hr Ozone Concentration & Daily Maximum Temperature May 2018
Lindon
Spanish Fork
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (°C) (Lindon)
Days
0.100
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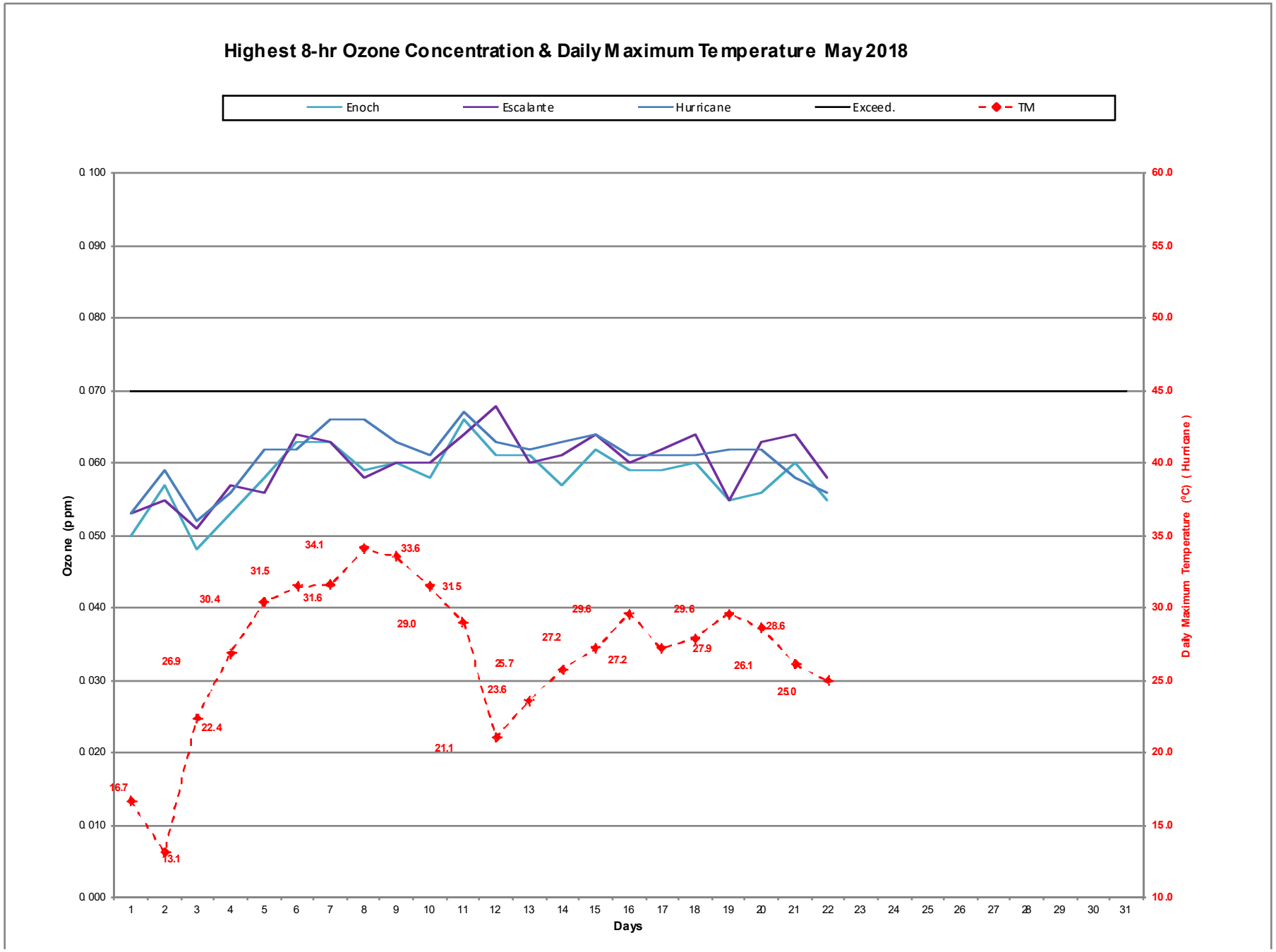
Highest 8-hr Ozone Concentration & Daily Maximum Temperature May 2018
Enoch
Escalante
Hurricane
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (°C) (Hurricane)
Days
0.100
0.090
0.080
0.070
0.060
0.050
0.040
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