AIR QUALITY BOARD

Meeting
October 3, 2018

Department of Environmental Quality
Division of Air Quality

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Utah
Department of Environmental Quality
Division of Air Quality

Utah Air Quality Board Meeting
195 North 1950 West, SLC – Room 1015
October 3, 2018 – 1:30 p.m.

Please Print

NAME	AFFILIATION
Erik Vernon	BLM
SUSAN HARDY	MAG
Jeff Musinger	Big West Oil
Erik Dettenmaier	Hill AFB
Megan Evans	Hill AFB
Richard Valentine	Salt Lake CO Health

AIR QUALITY

Utah
Department of Environmental Quality
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Utah Air Quality Board Meeting
195 North 1950 West, SLC – Room 1015
October 3, 2018 – 1:30 p.m.

Please Print

NAME	AFFILIATION
Kathy VanDame	Wasatch Clean Air Coalition
Jason Wells	Northrop Grumman
Sonja Wallace	Fetzer
MICHAEL BREHM	UOU
Debbie Sigman	Breathe Utah
Marcus Trail	Ramboll

UTAH STATE DEPARTMENT OF ENVIRONMENTAL QUALITY
DIVISION OF AIR QUALITY
AIR QUALITY BOARD

REQUEST TO MAKE COMMENTS

Today's date: 10/3/18 Phone: (801) 502-3883

Name (please print): Jessica Reimer

Organization or affiliation: HEAL Utah

General area of comments:

Inclusion of UPA modeling into SIP public comment period.

UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY
OCT - 3 2018
DIVISION OF AIR QUALITY

Amount of time requested: 5 min

Will a written comment be submitted? in SIP comment period

****SUBMIT COMMENT TO BOARD SECRETARY PRIOR TO START OF MEETING****

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-066-18a

UTAH AIR QUALITY BOARD MEETING

FINAL AGENDA

Wednesday, October 3, 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 Meeting: November 7, 2018

III. Approval of the Minutes for September 5, 2018, Board Meeting.

IV. Propose for Public Comment with Department Fee Schedule: Operating Permit Program Fee for Fiscal Year 2020. Presented by David Beatty.

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

VI. Propose for Public Comment: Change in Proposed Rule R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits. Presented by Thomas Gunter.

VII. Propose for Public Comment: Five-Year Review: R307-361. Architectural Coatings. Presented by Thomas Gunter.

VIII. Staff Response to Petition for a Rule Change: Utah Petroleum Association Petition for a Rule Change. Presented by Thomas Gunter.

IX. 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
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

UTAH AIR QUALITY BOARD MEETING
September 5, 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, Erin Mendenhall, Cassady Kristensen, Kevin Cromar, Mitra Kashanchi, Randal Martin, Alan Matheson, Arnold Reitze, and William Stringer

Executive Secretary: Bryce Bird

II Annual Election of Chair and Vice-Chair

Mr. Bird opened nominations for Chair of the Air Quality Board.

- Michael Smith motions to nominate Erin Mendenhall for Chair of the Air Quality Board. Cassady Kristensen seconded. No other nominations were made and nominations ceased. The Board approved unanimously.

Ms. Mendenhall opened nominations for Vice-Chair of the Air Quality Board.

- Kevin Cromar nominates Cassady Kristensen and was seconded by Ms. Kashanchi. No other nominations were made and nominations ceased. The Board approved unanimously.

III. Date of the Next Air Quality Board Meeting: October 3, 2018

IV. Approval of the Minutes for June 6, 2018, and August 7, 2018, Board Meetings.

- Mitra Kashanchi moved to approve the minutes with correction to the August meeting date. Arnold Reitze seconded. The Board approved unanimously.

Alan Matheson enters the meeting.

V. R. Chapman Construction Company. Settlement Agreement. Presented by Jay Morris.

Jay Morris, Minor Source Compliance Manager at DAQ, stated that staff conducted an annual compliance inspection at R. Chapman Construction's Harmston aggregate pit near Roosevelt, Utah on August 16, 2016. DAQ's inspector identified 23 separate violations as a result of that inspection and the following records review. On August 22, 2017, another inspector observed two repeat violations for failing to control fugitive dust. The DAQ attempted to negotiate with R. Chapman Construction to settle these violations since December 2017. DAQ sent multiple letters and emails and left many unanswered phone messages for the company. The Attorney General's Office (AGO) became involved in April 2018 to attempt to settle these violations with the company. R. Chapman Construction was notified in July 2018 from the AGO that a complaint would be filed in court if an administrative settlement could not be reached by August 10, 2018. A signed settlement was received on August 9, 2018, along with a schedule for coming back into compliance. Under Section 19-2-104 of the Utah Code, this memorandum is submitted to the Board for review since the penalty exceeds $25,000. The DAQ will withhold any further action on this case until the Board approves or disapproves the settlement. Staff recommends that the Board approve the settlement of $37,667.

In discussion, the Board expressed concern about the length of time between the initial inspection of violations found in 2016 and the follow-up inspections. In addition, staff was asked to explain how DAQ determines the penalty amount. Staff explained that typically these types of sites are inspected every 2-3 years. When a violation is identified, a follow-up inspection is planned the next year, or more frequently, if it is determined more frequent inspections are needed. For this source, part of the reason for follow-up inspection a year later was that the source was working through the process of obtaining an approval order. The penalty amount is determined based on the criteria listed on the penalty worksheet. In addition, August 10, 2018, was the deadline date for the settlement agreement because the statute of limitation is two years and the DAQ would lose its ability to settle the violations if a resolution was not reached.

Staff was asked if the Board has authority to examine the frequency at which the DAQ does follow-up inspections, and have the costs listed on the penalty worksheet been examined in the last couple of years? Staff responded that the compliance costs are funded from the state's general fund and are not tied to the work effort or the cost to bring a source back into compliance. All penalties that the division settles or that are adjudicated and awarded by the courts are returned to the state's general fund. It is within the Board's authority to examine the costs associated with compliance penalties. The penalty worksheet is based on R307-130 which is established by the Board. The statutory amount is established by the legislature which would require legislative approval to change the maximum daily penalty.

The Board requested that staff provide a briefing on R307-130, General Penalty Policy, and the division's inspection enforcement policy/strategy.

- Erin Mendenhall motioned that staff present to the Board how willful negligent actions could be required to have an expedited remedy, present the Board with some options to consider the per day violations amounts for Category A, B, C, and D, and also include a briefing on the division's procedures of compliance inspections. Arnold Reitze seconded. The motion carries with a vote of seven in favor (E. Mendenhall, C. Kristensen, K. Cromar, M. Kashanchi, R. Martin, A. Reitze, and W. Stringer) and one opposed (M. Smith).

- Kevin Cromar motioned that the Board approve the R. Chapman Construction Company settlement agreement amount of $37,667. William Stringer seconded. The Board approved unanimously.

VI. Propose for Public Comment: New Rule R307-511. Oil and Gas Industry: Associated Gas Flaring. Presented by Thomas Gunter.

Thomas Gunter, Rules Coordinator at DAQ stated that some oil and gas wells throughout the state are unable to utilize the streamlined permitting process approved by the Board in January 2018. Rule 307-511, if implemented, will enable these oil and gas wells to utilize the permit-by-rule process by requiring the associated natural gas from operating wells to be controlled as required for other equipment. Staff recommends that the Board propose new rule 307-511 for a 30-day public comment period.

Sheila Vance, Environmental Scientist at DAQ, added that staff went through a stakeholder process with this rule which included industry as well others that have expressed an interest in the oil and gas rules. Based on comments from industry, some changes were made and included in this rule proposal. Staff then responded to questions.

Up to this point, has flaring not been an option, and is the new rule consistent with the Utah Division of Oil, Gas, and Mining (DOGM) who in the past had taken a firm stand against flaring in certain areas? When a source reviews their annual emissions, if a source found they were in excess of 5 tons per year they would need a permit. This new rule allows a source the option to use this control strategy and go through the registration process and not have to file for a minor source permit. This is consistent with DOGM and is something a source is already doing.

What is the typical timeframe that DAQ would want to access record keeping on emergency release flares and is there a requirement for reporting the releases? A source would keep its records as part of the normal operations and would need to produce those records to DAQ as requested, or as part of a source's emissions inventory which is every three years. There is no reporting requirement, only a record keeping requirement. Staff was also asked if DAQ would think about either extending the number of years a source would need to keep records or a reporting requirement on emergency release flares. Staff responded that that this is something that can be addressed during the public comment period.

Is this new rule a potential mechanism for a better inventory of how many wells there are in the state? Not necessarily, the rules that were previously presented and approved by the Board in January 2018 had the inventory requirement. The sources for the new rule would have already fallen under the requirement to report an inventory to the DAQ. This rule would be a subset of the inventory requirement and sources would now be able to register and certify that they are going to follow the R307-500 series of rules. There are approximately 3,000 wells under state air quality jurisdiction which would be affected by this rule.

How is the definition for emergency release related to the unavoidable breakdown rule? The unavoidable breakdown rule is a very broad and general rule for all sources. This new rule is very specific for oil and gas wells. Staff sees the new rule as a subset of the unavoidable breakdown rule. Is there anything in the rule that would help to keep track of a particular well or group of wells that were having frequent emergency upsets? As the rule is written, there is no reporting requirement. This is also something that can be addressed during the public comment period.

- Michael Smith motioned that the Board propose new rule, R307-511, for a 30-day public comment. Kevin Cromar seconded. The Board approved unanimously.

VII. Propose for Public Comment: Amend UTAH State Implementation Plan. Control Measures for Area and Point Sources, Fine Particulate Matter, Serious Area PM2.5 SIP for the Salt Lake City, UT Nonattainment Area. Section IX. Part A.31. Presented by Bill Reiss.

Bill Reiss, Environmental Engineer at DAQ, gave a history of the events that have happened since last September. Most notably, staff had the opportunity to take a look at the ambient air quality data collected in northern Utah which enabled us to recover data that initially could not be entered into the record. Also, DAQ has completed the BACT work. Part H was proposed for public comment in June 2018 and staff is currently working on response to comments, which staff plans to present to the Board this October. Finally, staff did some additional work with the air quality model, and as you will see in the state implementation plan (SIP) section devoted to the attainment demonstration, we were able to compare what the model was telling us to some of the science that was revealed during the airplane study last year.

This item is the serious area SIP for the Salt Lake City $PM_{2.5}$ nonattainment area (NAA). In addition to the moderate area SIP for this area, the serious area SIP includes a demonstration that the area will attain the NAAQS by the end of 2019 and has provisions to insure the implementation of best available control measures and technologies (BACM/BACT). It also contains: emissions inventories for the base-year and the attainment year as well as a couple of milestone years; mobile source emission budgets for the purposes of transportation conformity; quantitative milestones which demonstrate RFP; and contingency measures.

Chapter 6 contains the attainment demonstration. As required, the air quality modeling is included in the analysis, but the modeling alone does not conclude a likelihood that we will attain the national ambient air quality standards (NAAQS) by the attainment date at every monitor in the NAA. Section 6.2 goes on to explain that the modeling guidance and the $PM_{2.5}$ implementation rule allow for the consideration of other information when determining whether attainment may be reached by the attainment date. The modeling and the additional information together make up a weight-of-evidence (WOE) to all be considered as a whole. So overall, the model is performing well. Good enough that we can go ahead and use it for regulatory purposes, but still there are some uncertainties inherent in the analysis.

Section 6.2 goes on to present some of the uncertainties in the modeling analysis which generally include emissions inventories, areas source emission in particular but also involves some non-criteria pollutants which may be important to the chemistry in the model. Meteorological (met) data is another area of uncertainty, especially given the resolution needed to feed the air quality model. The met data is generated by its own model called WRF. The met data also becomes difficult to approximate in a geographically complex terrain such as the Salt Lake valley. The air quality model itself also hosts a lot of uncertainty and is still just an approximation of what is going on.

In regards to the weight-of-evidence, apart from all the modeling and theoretical analysis, we also present some empirical evidence that shows a relationship between the control of precursor emissions and the improvements in $PM_{2.5}$. The ambient data collected in the SLC NAA show that ambient concentrations of $PM_{2.5}$ are declining. Trends in emissions data show a large and steady decline in NO_x and VOC emissions, and relatively flat trends in SO_2 and $PM_{2.5}$. Looking at the emissions and monitored data trends side-by-side, we see good agreement in the decline of both NO_x and SO_2. We don't monitor for VOC. We also see improvement in our monitored $PM_{2.5}$ data even though the emissions of direct $PM_{2.5}$ have remained relatively flat over that time. Taken together, we think that we have been successful at controlling our $PM_{2.5}$ concentrations with a strategy largely focused on controlling $PM_{2.5}$ precursor emissions.

Looking ahead, we anticipate even more improvement in the emissions of both NO_x and VOC. Given the past history we have of improving $PM_{2.5}$ concentrations by virtue of controlling NO_x, VOC, and SO_2, we would continue to expect improvements in the ambient $PM_{2.5}$. It might be expected that the air quality model would show improvement in the future years, but as indicated in the discussion on uncertainties, there are a number of issues that suggest that the model is a bit stiff in its sensitivity to reductions in NOx, which might lead to giving more weight to the empirical evidence that is presented along with the modeling analysis.

As a final piece of the weight-of-evidence, a supplemental analysis of the modeling that stems from the continued scrubbing of the air quality data, where, at Rose Park, a daily value has been identified as the 98th percentile value for 2015, which could potentially be excluded as an exceptional event because it was influenced by wild land fire. If the Rose Park value were to be flagged and removed for regulatory purposes, the 98th percentile for 2015 would drop 2.1 ug/m^3 and then the modeling result would pass on its own. In essence, the entire weight-of-evidence supports the likelihood that the SLC NAA will attain the NAAQS in 2019, which is our attainment year. Mr. Reiss then answered several questions from the Board.

After this summer, are we moving in the direction of having a summer $PM_{2.5}$ problem, and if so, what is the plan for what is becoming the new normal of summer $PM_{2.5}$? The plan is to do what we are currently doing. That may change going forward. We've had an unusually high smoke summer in which DAQ intends to flag certain events. We can control what happens here in the valley, but smoke due to transport from other states is difficult for us to control.

Are you following EPA in its process of reviewing their rules for exceptional events? EPA's process of reviewing its exceptional events rule has been ongoing for about 10 years. The rule is a difficult one for EPA because there are quite a bit of these events that they may be expected to approve. Fortunately, for $PM_{2.5}$ there is an acceptance that the concentrations are affected by wild land fire and so we have had success in getting these types of events approved. Ozone is often very difficult to get excluded from the regulatory record because wild land fires affect ozone values in more complex situations.

Explain why the model didn't work for Rose Park, and would DAQ expect the same results of the model for Part A? Yes, DAQ might consider the same result for Part A. Staff has been working on responses to the comments received on Part H. In working on the response to comments alongside with the model, shortcomings of the model have been identified. One of which is in its failure to see a benefit from some of the emissions reductions that DAQ expects to see in the next five years.

If DAQ included the precursor demonstration that we saw in Part H into Part A, would that help the case as far as the weight-of-evidence DAQ wanted to use? It would be based on the model of which there is concern. In recognition of the comments received concerning precursor emissions in the context of Part H, DAQ is now considering whether or not it should be controlling NOx, VOC, SO2, and ammonia. Ultimately, the EPA Administrator will need to approve what we have done. Although not required, DAQ may choose to submit optional demonstrations with the SIP submitted for EPA approval.

Would the precursor demonstration require a public comment period before consideration by EPA, and does it make sense to include the precursor demonstration for public comment with this package? EPA does require a public comment period on everything they propose. As far as including the precursor demonstration with this rule package for public comment, DAQ is not prepared to submit it for public comment with this package or to EPA on behalf of anyone else. However, the public comment period surrounding this package is an opportunity to introduce all of it on the record, not only in the context of

Part H, but also on the context of the attainment demonstration that is included in this part of the SIP. In this way, it could be brought to EPA's attention, if it goes for approval in their comment period.

The support documents are not available to the public at this time, but they will be available as soon this rule package goes out for public review on October 1, 2018.

In the listed model adjustments, does DAQ have data on the lowered residential wood smoke emissions to reflect burn ban compliance during forecasted high $PM_{2.5}$ days? Yes, there is data. An episode of 10 days in 2011 was chosen and within the episode there is a record of what DAQ did to call a burn ban.

Explain the statement about artificially adding non-inventoried ammonia emissions to the inventoried emissions that are input into CAMx. Ammonia is difficult to both monitor and to calculate in the inventory. Ammonia was injected into the model because the monitors were showing something the model was not predicting. The model showed we were short by 40% of what the model thought it ought to be in order that when we tried to reproduce the past, we were able to build the ammonium nitrate we observed.

Public comment from Jeanette King with the Utah Petroleum Association (UPA) was introduced. Ms. King stated that the federal Clean Air Act and in the EPA's implementation rule for $PM_{2.5}$ specifically provide that controls should not be imposed for precursors that are known to insignificantly contribute to $PM_{2.5}$ levels. UPA retained the model developer for the CAMx model, Ramboll, that UDAQ is using in its attainment demonstration, to evaluate the contribution of major stationary source precursors to the nonattainment problem in the SLC NAA. Ramboll demonstrates that based on the particulars of the SLC NAA, precursors from certain sources do not significantly contribute to the $PM_{2.5}$ problem and should not be subject to further controls. The Ramboll analysis is relevant to both the attainment demonstration that UDAQ is now proposing and the Part H rulemaking and should be included as part of the information that is available for public comment on the attainment demonstration. EPA has been clear that it expects a full public discourse on the precursor demonstrations and we believe that it is only appropriate that full consideration be given to this very relevant analysis that has a direct bearing on the attainment demonstration and control strategy. Furthermore, because the attainment demonstration and precursor demonstration analysis are inexorably related to the Part H rulemaking, it would be premature to conclude that rulemaking apart from the attainment demonstration. UPA requests that UDAQ submit the previously submitted precursor demonstrations to public comment that the UDAQ staff consider that the precursor demonstrations be added to the SIP, and that the Board postpone the rulemaking for the Part H measures until such time that the Board takes final action on the attainment and precursor demonstrations.

- Cassady Kristensen motioned that the Board approve the SIP control measures for area and point sources, Section IX, Part A.31, including the precursor demonstration submitted by UPA, for public comment. Mitra Kashanchi seconded. The Board approved unanimously.

VIII. Propose for Public Comment: Amend R307-110-10. Section IX, Control Measures for Area and Point Sources, Part A, Fine Particulate Matter. Presented by Thomas Gunter.

Thomas Gunter, Rules Coordinator at DAQ, stated that this rule will have to be incorporated into the Utah Air Quality Rules. R307-110-10 is the rule that incorporates the amendments. If the Board adopts the amendments proposed to Part A, these amendments will become part of Utah's state implementation plan when the rule is finalized. Staff recommends that the Board propose the amended rule 307-110-10 for a 30-day public comment period.

- Arnold Reitze motioned that the Board propose for public comment the amended R307-110-10, Section IX, Control Measures for Area and Point Sources, Part A, Fine Particulate Matter. Cassady Kristensen seconded. The Board approved unanimously.

IX. Informational Items.

A. Air Toxics. Presented by Robert Ford.

Rusty Ruby, Compliance Branch Manager at DAQ, explained that schools have a requirement to do an Asbestos Hazard Emergency Response Act (AHERA) management plan. In the listed school district's penalties, one did not do the annual notification requirement and the other did not submit its AHERA management plan. These requirements have been in existence since 1986.

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

C. Monitoring. Presented by Bo Call.

Bo Call, Monitoring Section Manager at DAQ, updated the Board on the monthly graphs noting the high summer activity with wild land fires. As far as exceptional events related to smoke and the wild land fires, only one state has successfully demonstrated an exceptional event specific to ozone with a 3 parts per billion reduction. Staff will be working on and applying for an exceptional event for the events around the wild land fires. Ozone numbers across the board have been high all summer. The Lindon monitor had 22 days that exceeded the standard this year.

When asked if there is association with wild land fires and VOC concentrations, staff responded that yes, VOCs and other compounds that come off wild land fires impact ozone. The sort of fuel burning, how hot the fire is burning, how aged the smoke plume is, and where the fire is coming from all make a difference.

Is there any data across the West that would suggest transport from wild land fires? Yes, the state has remote monitors in the network that see exceedances of the standard, which is a good indication of regional transport of ozone.

The communication to the public on the UtahAir app is ozone in the summer and fine particulate in the winter. Is that still correct, or are both pollutants being communicated to the public? The UtahAir app does show both pollutants. A person would just need to toggle over to the pollutant of concern. DAQ forecasts for all the pollutants, and action days could be based on either ozone, particulate, or both.

Kevin Cromar made the motion that staff does a presentation on how staff communicates air quality to the public. Seconded by William Stringer and unanimously approved by the Board.

D. Other Items to be Brought Before the Board.

Public comment from citizen Sandy Neild was introduced. Ms. Neild commented that staff today mentions that chlorine levels have raised recently. She suggests that staff look at diesel exhaust fluid because it's made in 80% of the trucks on the road today. Ms. Neild also wanted to speak with the Board about ethanol. Utah is not required to put ethanol in gasoline, but it does at a minimum of 10%. When ethanol is put into gasoline, the volatility of the gasoline is raised two points, and you lose 30% of your fuel economy when 10% of ethanol is added. One of the worst things this country could have done was to take a food source and turn it into a gasoline. We as tax payers are paying for this in our federal tax. Ms. Neild would like for Utah to take the 10% of ethanol out of Utah's gasoline, go back to the federal government and get the tax money back. This would also lower the VOCs and make our air quality better.

E. Board Meeting Follow-up Items.

- DAQ staff will present to the Board how willful negligent actions could be required to have an expedited remedy, present the Board with some options to consider the per day violation amounts for Category A, B, C, and D, and also include a briefing on the division's procedures of compliance inspections.

- DAQ staff will do a presentation on how staff communicates air quality to the public.

Meeting adjourned at 3:26 p.m.

ITEM 4

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-062-18

M E M O R A N D U M

TO: Air Quality Board

THROUGH: Bryce C. Bird, Executive Secretary

THROUGH: Marty Gray, Permitting Branch Manager

FROM: David Beatty, Operating Permit Section Manager

DATE: September 12, 2018

SUBJECT: Propose for Public Comment with Department Fee Schedule: Operating Permit Program Fee for Fiscal Year 2020.

Title V of the Clean Air Act Amendments of 1990 (CAAA) requires the State of Utah to develop an Operating Permit Program (OPP), to include a fee which is used solely to fund all direct and indirect costs associated with administering the program for each state fiscal year. Additionally, any unused funds are returned to the sources as a fee reduction in the following fiscal year. Section 19-2-109.1(4)(a) of the Utah Conservation Act authorizes the Utah Air Quality Board (the Board) to propose to the legislature an annual emission fee that conforms to Title V of the CAAA for each ton of chargeable pollutant. The fee is included as part of the Department's fee schedule each fall.

Utah began collecting an emission fee of $25 per ton during fiscal year 1993, to fund development of the program. The fee has changed in varying increments from -4.3% to +17.9%. The current fee charged to fund fiscal year 2019 is $78.86 per ton of emissions. Most fee increases have been the result of reduced emission tonnages by sources or increasing salaries and benefits to staff as part of legislative approved cost of living increases. An additional increase for fiscal year 2020 is the result of staff salary increases and a further reduction of 1,700 tons of chargeable pollutants. Also, staff size has been reduced from 39 full-time employees (FTEs) in 1995 to a level of 30 FTEs for fiscal year 2020; this has assisted in keeping fee increases as low as possible.

For fiscal year 2020, Air Quality staff is basing its proposal on a projected emissions inventory of 53,900 tons, an amount 1,700 tons lower than fiscal year 2019. The fee calculation is shown in the table below and shows a fee of $82.75 for fiscal year 2020, an increase from fiscal year 2019 of 4.93%.

Operating Permit Emission Fee for Fiscal Year 2020

FY2019 Salary + Benefits		$3,377,967	
FY2020 Projected Cost Of Living Increase	2%	$67,559	
FY2020 Projected Salary + Benefits with Projected Increase			$3,445,526
FY2020 Projected Indirect Costs	12.61%	$434,481	
FY2020 Projected Direct Costs		$580,000	
FY2020 Projected Total Expenditures			$4,460,007
FY2020 Projected Fee Tonnage		53,900	
Fee Rate Per Ton of Emissions			$82.75
FY2018 Surplus		$0	
Surplus Reduction in Fee		$0.00	
FY2020 Proposed Fee Rate Per Ton of Emissions			**$82.75**
		$3.89	Increase

Current Fee (FY2019) is $78.86

Recommendation: Staff recommends the Board submit as part of the Department's fee schedule, a proposed fee of $82.75/ton for the operating permit program for fiscal year 2020.

ITEM 5

State of Utah
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Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQ-067-18

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: September 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.

Part H Amendments Triggering Changes in Proposed Rule

On June 6, 2018, the Board proposed for public comment amendments to SIP Subsection IX. Part H Control Measures for Area and Point Sources, Emission Limits and Operating Practices Subparts 1, 2, 11 and 12. The terms in these subparts enforce the plan requirements for stationary sources located in the Salt Lake City $PM_{2.5}$ nonattainment area (SLC NAA).

The originally proposed amendments to subparts 1 and 2 specifically affect PM_{10} requirements, but were included to correct a calculation error, add clarification, and provide consistency throughout Part H. The amendments addressing $PM_{2.5}$ in subparts 11 and 12 were proposed to support a serious area state implementation plan (SIP) for the SLC NAA, providing therein for the implementation of best available control measures and technologies (BACM/BACT) at the large stationary "point" sources in the nonattainment area. These provisions include enforceable emission limitations as well as schedules and timetables for compliance.

Public comments were accepted from July 1, 2018, through August 15, 2018. Attachments to this memo summarize the comments that were received and provide UDAQ's responses to those comments. In addition to the public comments, UDAQ has received supplemental information for the BACM/BACT reviews for four of the stationary sources: Hexcel, Rio Tinto Kennecott, Compass Minerals, and ATK Launch Systems, Inc. Promontory. This supplemental information has triggered substantive changes that UDAQ believes should be proposed for public comment.

Utah Petroleum Association Precursor Demonstration

The original Part H amendments were proposed by staff to the Board for consideration in advance of completing the remainder of the SIP, which includes the modeling and attainment demonstration. Staff explained that EPA's Fine Particulate Matter Implementation Rule pertains to the provisions to ensure BACM/BACT as "generally independent" of attainment, and as such are to be determined without regard to the specific attainment demonstration for the area.

Of the many comments received, one in particular from the Utah Petroleum Association (UPA) takes issue with this "general independence," and contends that it was premature to consider BACM/BACT for all four plan precursors for the major stationary point sources until the air quality modeling could ascertain whether in fact certain $PM_{2.5}$ precursor emissions could or could not be exempted from the BACM/BACT provisions. Furthermore, UPA's precursor demonstration that supported the comment was proposed for public comment by the Board during the September board meeting, prior to UDAQ having the opportunity to review or perform an analysis.

The intent of a precursor demonstration is to exclude precursors that do not significantly contribute to the formation of secondary $PM_{2.5}$ in the particular airshed and the demonstration is typically prepared and submitted by the local air quality agency. Since the appropriateness of a precursor demonstration is ultimately decided by the EPA Administrator, UDAQ cannot know the result until after this rulemaking is complete. Until that time, UDAQ will continue to review and identify provisions to ensure BACM/BACT for all four plan precursors under the guidance of the Clean Air Act and state implementation plan requirements in order to meet timelines discussed with EPA.

UDAQ's preliminary review of the technical analysis attached to UPA's comment on precursor emissions raises a few concerns. First and foremost, UDAQ would like to perform the analysis with input and participation from the final arbiter, EPA, rather than accept the conclusions proffered by the commenter.

Prior to UDAQ conducting our own analysis, we submit to the Board several reservations with UPA's precursor demonstration analysis. Ambient $PM_{2.5}$ in the SLC NAA airshed is largely composed of secondary $PM_{2.5}$ formed by precursors, not primary $PM_{2.5}$. In addition, as shown in the SLC NAA SIP, empirical evidence points to the success in declining concentrations of ambient $PM_{2.5}$ from controlling precursor emissions. This begs the question: is a major stationary source precursor demonstration for all four plan precursors appropriate for the SLC NAA?

Furthermore, the attainment demonstration in the SIP includes, in addition to the air quality modeling, a weight-of-evidence (WOE) discussion that illustrates potential shortcomings in the model (CAMx) that affect its sensitivity to simulated reductions in precursor emissions. UPA used the same model (with some input variation) to perform their precursor demonstration and the same shortcomings may have been perpetuated.

UPA's precursor demonstration analysis was based on EPA's draft guidance, which identifies a threshold of 1.5µg/m3. Considering Utah has previously implemented emissions controls that resulted in large reductions, Utah continues to look at controls that may only produce marginal benefits. Therefore, the threshold established in the draft guidance may not be appropriate in the SLC NAA, particularly when evaluating the precursors cumulatively.

UDAQ encourages the Board to consider the information presented in this memo and in exercising its rulemaking authority, "[t]he board may establish emission control requirements by rule that *in its judgment may be necessary* to prevent, abate, or control air pollution that may be statewide or may vary from area to area, taking into account varying local conditions. (Utah Code Ann. § 19-2-109(2)(a))."

Staff Recommends Proposing for Public Comment Further Amendments to Part H

UDAQ recommends that the Board move forward with the BACM/BACT provisions by approving UDAQ's recommendation in this memorandum. In addition to the procedural reasoning that the SIP is already behind the statutory due date for submittal, 2019 is the attainment year identified in the SIP. As such it is important to have a full suite of controls in place such that the monitored values collected may be as low as they can be.

Additionally, should the remainder of 2018 continue to show monitored values below the NAAQS, the SLC NAA is positioned to complete a 3-year data set which would allow for a finding that the area is attaining the standard through the utilization of the Clean Data Option. This may ultimately allow for a maintenance plan and subsequent redesignation of the area. Should this become the case, any subsequent violation of the standard would result in the area becoming designated once more as a moderate nonattainment area. BACT provisions are still required before any of these steps would become possible.

UDAQ is recommending that Part H be further amended to accommodate the aforementioned supplemental BACM/BACT information for the four stationary sources. Specific revisions to those sections of Part H have been identified herein (see attachment A). This should ultimately result in a final action on Part H in January. Part H could then be submitted to EPA in February, which is only two months behind the initial schedule. UDAQ is currently conducting an in-depth technical analysis of UPA's precursor comment. This analysis will likely be completed by the end of October. Any findings by UDAQ, EPA, or other parties will be incorporated into Part H prior to the proposed final action in January.

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

Attachments A: Amended SIP Subsection IX. Part H: Emission Limits and Operating Practices. Specifically Proposed for Amendment are Requirements in Subparts H. 1, 2, 11, and 12.

Attachments B: Response to Comments Received During the Previous SIP Subsection IX. Part H Comment Period

ATTACHMENT A

Utah State Implementation Plan

Emission Limits

and Operating Practices

Section IX, Part H

Adopted by the Air Quality Board
[~~December 7~~], 201[~~6~~]9

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

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

b. Definitions.

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

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

c. Recordkeeping and Reporting

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

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

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

d. Emission Limitations.

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

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

e. Stack Testing.

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

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

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

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

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

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

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

[~~G~~]H. A stack test protocol shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by the Director. [~~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~~]I. The production rate during all compliance testing shall be no less than 90% of the maximum production rate achieved in the previous three (3) years. If the desired production rate is not achieved at the time of the test, the maximum production rate shall be 110% of the tested achieved rate, but not more than the maximum allowable production rate. This new allowable maximum production rate shall remain in effect until successfully tested at a higher rate. The owner/operator shall request a higher production rate when necessary. Testing at no less than 90% of the higher rate shall be conducted. A new maximum production rate (110% of the new rate) will then be allowed if the test is successful. This process may be repeated until the maximum allowable production rate is achieved.

f. Continuous Emission and Opacity Monitoring.

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

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

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

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

g. Petroleum Refineries.

i. Limits at Fluid Catalytic Cracking Units (FCCU)

A. FCCU SO_2 Emissions

I. [~~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~~]burn-off.

II. Compliance with this limit shall be determined by following the stack test protocol specified in 40 C.F.R. §60.106(b) or 40 C.F.R. §60.104a(d) to measure PM emissions on the FCCU. Each owner operator shall conduct stack tests once every three (3) years 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 $PM_{2.5}$ nonattainment area or any PM_{10} nonattainment or maintenance area shall require:

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

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

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

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

iv. No Burning of Liquid Fuel Oil in Stationary Sources

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

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

v. Requirements on Hydrocarbon Flares.

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

B. [~~By n~~]No later than January 1, 2019, all major source petroleum refineries in or affecting [~~a designated~~]any $PM_{2.5}$ non[-]attainment area or an PM_{10} nonattainment or maintenance 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 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~~]. NOx emissions for the FCC are monitored with a continuous emission monitoring system. Refinery Boilers and heaters over 40 MMBtu/hr but less than 100 MMBtu/hr are in compliance with monitoring and work practice standards of Subpart DDDD of Part 63.

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

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

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

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

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

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

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

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

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

iii. Source-Wide SO_2 Cap

[~~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.

vii. No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:

Emission Unit	**Control Equipment**
FCCU Regenerator	Flue gas blowback "Pall Filter", quaternary cyclones with fabric filter
H-404 #1 Crude Heater	Ultra-low NO_x burners
Refinery Flares	Subpart Ja, and MACT CC flaring standards
SRU	Tail gas incinerator and redundant caustic scrubber
Product Loading Racks	Vapor recovery and vapor combustors
Wastewater Treatment System	API separator fixed cover, carbon adsorber canisters to be installed 2019.

b. Bountiful City Light and Power: Power Plant

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

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

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

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

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

iii. Combustion Turbine Startup / Shutdown Emission Minimization Plan

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

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

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

c. Central Valley Water Reclamation Facility: Wastewater Treatment Plant

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

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

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

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

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 stack test~~]annualy. 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.

v. Compressor Engine Requirements

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

Engine Number	NO_x in ppmvd @ 0% O_2
K35001	236
K35002	208
K35003	230

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

vi. Flare Calculation

A. Chevron's Flare #3 receives gases from its Isomerization unit, Reformer unit as well as its HF Alkylation Unit. The HF Alkylation Unit's flow contribution to Flare #3 will not be included in determining compliance with the flow restrictions set in IX.H.1.g.v.B

i. No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:

Emission Unit	**Control Equipment**
Boilers: 5, 6, 7	Low NOx burners and flue gas recirculation (FGR)
Cooling Water Towers	High efficiency drift eliminators
Crude Furnaces F21001, F21002	Low NOx burners
Crude Oil Loading	Vapor Combustion Unit (VCU)
FCC Regenerator Stack	Vacuum gas oil hydrotreater, Electrostatic precipitator (ESP) and cyclones
Flares: Flare 1, 2, 3	Flare gas recovery system
HDS Furnaces F64010, F64011	Low NOx burners
Reformer Compressor Drivers K35001, K35002, K35003	Selective Catalytic Reduction (SCR)
Sulfur Recovery Unit 1	Tail gas treatment unit and tail gas incineration
Sulfur Recovery Unit 2	Tail gas treatment unit and tail gas incineration
Wastewater Treatment Plant	Existing wastewater controls system of induced air flotation (IAF) and regenerative thermal oxidation (RTO)

e. Hexcel Corporation: Salt Lake Operations

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

A. 5.50 MMscf of natural gas consumed per day.

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

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

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

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

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

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

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

f. Holly Refining and Marketing Company

i. Source-wide PM_{10} Cap

[~~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. As an alternative to a continuous parameter monitor system or continuous opacity monitoring system for PM emissions from any FCCU controlled by a wet gas scrubber, as required in Subsection IX.H.1.g.i.B.III, the owner/operator may satisfy the opacity monitoring requirements from its FCC Units with wet gas scrubbers through an alternate monitoring program as approved by the EPA and acceptable to the Director.

B. The default emission factors listed in IX.H.2.[~~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.

v. <u>No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:</u>

1)

Emission Unit	Control Equipment
Process heaters and boilers	Boilers 8&11: LNB+SCR Boilers 5, 9 & 10: SCR Process heaters 20H2, 20H3 23H1, 24H1, 25H1: ULNB
Cooling water towers 10, 11	High efficiency drift eliminators
FCCU regenerator stacks	WGS with Lo-TOx
Flares	Flare gas recovery system
Sulfur recovery unit	Tail gas incineration and WGS with Lo-TOx
Wastewater treatment plant	API separators, dissolved gas floatation (DGF), moving bed bio-film reactors (MBBR)

g. Kennecott Utah Copper (KUC): Mine

i. Bingham Canyon Mine (BCM)

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

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

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

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

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

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

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

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

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

D. Implementation Schedule

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

ii. Copperton Concentrator (CC)

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

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

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

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

i. Utah Power Plant

A. Boilers #1, #2, and #3 shall [~~cease operations permanently upon commencing operations of Unit #5 (combined-cycle, natural gas-fired combustion turbine)~~]<u>not operate</u>.

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

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

III. Startup / Shutdown Limitations:

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

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

3. Definitions:

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

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

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

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

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

Pollutant	Test Frequency
I. PM_{10}	every year

II. NO_X every year

D. The following requirements are applicable to Unit[~~s #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	grains/dscf 68^{o}F, 29.92 in. Hg	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~~]
2. NO_X<ins>*</ins>		
[~~Unit #4~~		~~336~~
~~(Unit 4 after January 1, 2018)~~		~~60~~]

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

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

Pollutant	grains/dscf 68^{o}F, 29.92 in Hg	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~~]

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

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

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

[~~Initial compliance testing is required for Unit #4 after low NO_x burner installation.~~] Initial testing shall be performed when burning natural gas and also when burning coal as fuel. The initial test date shall be performed within 60 days after achieving the maximum heat input capacity
production rate at which the affected facility will be operated and in no case later than 180 days after the initial startup of a new emission source.

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

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

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

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

2. Unit #4

(i) PM_{10} filterable 0.029

(ii) NO_x* [~~384~~]

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

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

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

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

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

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

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

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

ii. Tailings Impoundment

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

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

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

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

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

I. Alert the Utah Division of Air Quality promptly.

II. Continue surveillance and coordination of appropriate measures.

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

Kennecott Utah Copper (KUC): Smelter & Refinery

i. Smelter

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

I. Main Stack (Stack No. 11)

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

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

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

II. Holman Boiler

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

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

Emission Point	Pollutant	Test Frequency
I. Main Stack (Stack No. 11)	PM_{10} SO_2 NO_X	every year CEM CEM
II. Holman Boiler	NO_X	every three years &<u>CEMS or</u> alternate method according to 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~~	$\cancel{NO_X}$	~~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. Emissions of NO_x shall not exceed 336 ppmvd (@ 3% O_2, dry)

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

ii. Steam Generating Unit #2:

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

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

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

iii. Steam Generating Unit #3:

A. Emissions of NO_x shall be no greater than

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

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

B. Emissions of NO_x shall not exceed

I. 168 ppmvd (@ 3% O_2, dry), applicable between November 1 and February 28/29

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

iv. Steam Generating Units #1-3:

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

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

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

B. Emissions of NO_x from each turbine stack shall not exceed 5 ppmvd (@ 15% O_2 , dry). Emissions shall be calculated on a 30-day rolling average. This limitation applies to steady state operation, not including startup and shutdown.

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

vi. Combustion Turbine Startup / Shutdown Emission Minimization Plan

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

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

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

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

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

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

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

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

k. Tesoro Refining & Marketing Company

i. Source-wide PM_{10} Cap

[~~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~~]0.0019 lb/MMBtu
Condensable PM_{10}: [~~5.7 lb/MMscf~~]0.0056 lb/MMBtu

Plant gas:
Filterable PM_{10}: [~~1.9 lb/MMscf~~]0.0019 lb/MMBtu
Condensable PM_{10}: [~~5.7 lb/MMscf~~]0.0056 lb/MMBtu

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

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

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

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

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

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

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

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

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

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

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

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

ii. Source-wide NO_x Cap
[~~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~~]annually following the date of the last test. At that time a new flow-weighted average emission factor in terms of: lbs/MMbtu shall be derived [~~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~~]0.0006 lb/MMBtu
Propane: EF = [~~0.60 lb/MMscf~~]0.0006 lb/MMBtu
Diesel fuel: shall be determined from the latest edition of AP-42

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

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

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

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

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

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

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

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

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

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

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

B. 1.68 tons per day (tpd) for up to 21 days per rolling 12-month period, and
18)
C. 0.69 tpd for the remainder of the rolling 12-month period.

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

[~~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.

vi. No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:

Emission Unit	Control Equipment
FCCU / CO Boiler	Wet Gas Scrubber, LoTOx
Furnace F-1	Ultra Low NOx Burners
Tanks	Tank Degassing Controls
North and South Flares	Flare Gas Recovery
Furnace H-101	Ultra Low NOx Burners
Truck loading rack	Vapor recovery unit
Sulfur recovery unit	Tail Gas Treatment Unit
API separator	Floating roof (single seal)

l. University of Utah: University of Utah Facilities

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

Emission Point	Pollutant	ppmdv (3% O_2 dry)
A. Boiler #3	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. Emissions of NO_x shall not exceed 5ppmdv (@ 15% O_2, dry) on a 30-day rolling average.

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

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

H.4 Interim Emission Limits and Operating Practices

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

b. Petroleum Refineries:

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

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

B. Compliance Demonstrations.

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

For SO_x, the emission factors

are: Natural gas: EF = 0.60

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

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

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

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

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

c. Big West Oil Company

i. PM_{10} Emissions

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

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

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

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

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

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

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

ii. SO_2 Emissions

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

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

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

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

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

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

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

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

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

iii. NO_x Emissions

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

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

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

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

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

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

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

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

d. Chevron Products Company

i. PM_{10} Emissions

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

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

ii. SO_2 Emissions

A. Combined emissions of sulfur dioxide from gas-fired compressor drivers and all external combustion process equipment, including the FCC CO Boiler and Catalyst Regenerator, shal l 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 $PM_{2.5}$ and condensable PM, unless otherwise specified in the source specific conditions listed in IX.H.12 and IX.H.13.

e. Stack Testing:

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

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

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

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

19)

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

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

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

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

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

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

[~~J~~]I. A stack test protocol shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by the Director.

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

f. Continuous Emission and Opacity Monitoring

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

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

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

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

g. Petroleum Refineries.

i. Limits at Fluid Catalytic Cracking Units

A. FCCU SO_2 Emissions

I. [~~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~~]burn-off.

II. Compliance with this limit shall be determined by following the stack test protocol specified in 40 C.F.R. §60.106(b) to measure PM emissions on the FCCU. Each owner operator shall conduct stack tests once every [~~five~~]three years 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~~] or any PM10 nonattainment or maintenance area shall be subject to the flaring requirements of NSPS Subpart Ja (40 CFR 60.100a–109a), if not already subject under the flare applicability provisions of Ja.

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

vi. Requirements on Tank Degassing

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

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

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

I. Start date and time;

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

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

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

V. Description of vapor control device.

vii. No Burning of Liquid Fuel Oil in Stationary Sources

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

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

h. Catalytic Oxidation for VOC Control

i. Internal Combustion Engines

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

ii. Natural Gas Combustion Turbines

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

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

a. ATK Launch Systems Inc. Promontory

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

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

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

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

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

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

iii. Natural Gas-Fired Boilers

A. Building M-576

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

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

20)

B. Building M-14

I. The two 25 MMBTU/hr boiler shall be upgraded with low NO_x burners and flue gas recirculation by December 31, 2024. The boiler shall be rated at a maximum of 9 ppm.

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~~] NO_x emissions for the FCC are monitored with a continuous emission monitoring system. Refinery Boilers and heaters over 40 MMBtu/hr, but less than 100 MMBtu/hr, are in compliance with monitoring and work practice standards of Subpart DDDD of Part 63.

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

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

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

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

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

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

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

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

iii. Source-wide SO_2 Cap

[~~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.

vii. No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:

Emission Unit	**Control Equipment**
FCCU Regenerator	Flue gas blowback “Pall Filter”, quaternary cyclones with fabric filter
H-404 #1 Crude Heater	Ultra-low NO_x burners
Refinery Flares	Subpart Ja, and MACT CC flaring standards
SRU	Tail gas incinerator and redundant caustic scrubber
Product Loading Racks	Vapor recovery and vapor combustors
Wastewater Treatment System	API separator fixed cover, carbon adsorber canisters to be installed 2019.

[~~c. 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. (3-hr rolling average)

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

ii. No later than January 1, 2019, or upon source start-up, whichever comes later, a baghouse control technology shall be installed and operating on the Lime Production Kiln[~~ 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. (3-hr rolling average)

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

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

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

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

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

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

b. No ammonia or urea injection during shutdown.

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

[~~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
K35001	236
K35002	208
K35003	230

B. Initial stack testing to demonstrate compliance with the above emission limitations shall be performed no later than January 1, 2019 and at least once every three years thereafter. 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

21)

vii. No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:

Emission Unit	**Control Equipment**
Boilers: 5, 6, 7	Low NOx burners and flue gas recirculation (FGR)
Cooling Water Towers	High efficiency drift eliminators
Crude Furnaces F21001, F21002	Low NOx burners
Crude Oil Loading	Vapor Combustion Unit (VCU)
FCC Regenerator Stack	Vacuum gas oil hydrotreater, Electrostatic precipitator (ESP) and cyclones
Flares: Flare 1, 2, 3	Flare gas recovery system
HDS Furnaces F64010, F64011	Low NOx burners
Reformer Compressor Drivers K35001, K35002, K35003	Selective Catalytic Reduction (SCR)
Sulfur Recovery Unit 1	Tail gas treatment unit and tail gas incineration
Sulfur Recovery Unit 2	Tail gas treatment unit and tail gas incineration
Wastewater Treatment Plant	Existing wastewater controls system of induced air flotation (IAF) and regenerative thermal oxidation (RTO)

[~~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	1.3
Boiler #2	9.0	1.3

Compliance to the above emission limits shall be determined by stack test as outlined in Section IX Part H.11.e of this SIP. A compliance test shall be performed at least once every three years 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 concentration and 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)	Concentration Emission Rate (grains/dscf)
AH-500	1.61	0.01
AH-502	0.75	0.04
AH-513	1.49	0.0114
BH-001	0.37	0.01
BH-002	0.47	0.01
BH-008	1.15	0.01
BH-501	1.15	0.01
BH-502	0.06	0.0053
BH-503	0.23	0.01
BH-505	0.12	0.01
AH-1555	0.40	0.01
BH-1400	2.78	0.02
AH-692	0.12	0.01
BH-1516	0.22	0.01

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

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

iii. [~~$PM_{2.5}$ emissions to the atmosphere from the indicated emission point shall not exceed the following rates and concentrations:~~

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

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

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

22)

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

A. Emission limitations will not be listed here, part of the exhaust stream will include the NO_x generated from the oxidation of PAN in the carbon fiber production process and these emissions are not well defined. UDAQ evaluated the submittal in DAQ-2018-007701 for NOx. Due to the above statement, UDAQ cannot present a NO_x limit as part of the Emission Limits and Operating Practices of Section IX, Part H.f at this time. UDAQ is requesting the Board to approve an additional public comment period on Part H of the serious $PM_{2.5}$ SIP. UDAQ will work with the source to determine BACT for SO_2. UDAQ expects to complete the analysis and determine BACT prior to the start of the additional comment period, that is expected to begin November 1, 2018.

v. De-NO_x Water Direct Fired Thermal Oxidizer (DFTO) shall be installed on Fiber lines 13, 14, 15, and 16 to control NO_x emissions no later than December 31, 2024.

23)

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

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

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

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

Residence times shall be determined by:

$R = V / Q_{max}$
Where
R = residence time
V = interior volume of the incinerator – ft^3
Q_{max} = maximum exhaust gas flow rate – ft^3/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~~]g. 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. As an alternative to a continuous parameter monitor system or continuous opacity monitoring system for PM emissions from any FCCU controlled by a wet gas scrubber, as required in Subsection IX.H.11.g.i.B.III, the owner/operator may satisfy the opacity monitoring requirements from its FCC Units with wet gas scrubbers through an alternate monitoring program as approved by the EPA and acceptable to the Director.

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

Initial stack testing on all NSPS combustion equipment shall be conducted no later than January 1, 2019 and at least once every three (3) years 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.

vi. No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:

Emission Unit	**Control Equipment**
Process heaters and boilers	Boilers 8&11: LNB+SCR

	Boilers 5, 9 & 10: SCR Process heaters 20H2, 20H3 23H1, 24H1, 25H1: ULNB
Cooling water towers 10, 11	High efficiency drift eliminators
FCCU regenerator stacks	WGS with Lo-TOx
Flares	Flare gas recovery system
Sulfur recovery unit	Tail gas incineration and WGS with Lo-TOx
Wastewater treatment plant	API separators, dissolved gas floatation (DGF), moving bed bio-film reactors (MBBR)

[~~i~~]h. Kennecott Utah Copper (KUC): Mine

i. Bingham Canyon Mine (BCM)

40) A. Maximum total mileage per calendar day for ore and waste haul trucks shall not exceed[~~ combined per rolling 12-month period~~] 30,000 miles.
41)
42) 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.
43)
44) 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.
45)
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.
46)
III. Records of water and/or chemical dust control treatment shall be kept for all periods when the BCM is in operation.
47)
IV. KUC is subject to the requirements in the most recent federally approved Fugitive Emissions and Fugitive Dust rules.
48)
C. [~~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.(0.007 gr/dscf) $PM_{2.5}$ monitoring shall be performed by stack testing every three years.
49)
50) [~~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~~]D. Minimum design payload per ore and waste haul truck shall not be less than 240 tons. The minimum design payload for all trucks combined shall be an average of 300 tons.

ii. Copperton Concentrator (CC)

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

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

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

[~~k~~]j. 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.~~]The following requirements are applicable to Unit #4:

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. Unit #4 may then burn coal, only for the duration of the curtailment plus sufficient time to empty the coal bins following the curtailment. The Director shall be notified of the curtailment within 48 hours of when it begins and within 48 hours of when it ends.

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

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

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

III. [~~NH_4 2.0*~~]During the period from March 1 to October 31, Unit #4 shall use coal, natural gas, or oils as fuels.

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

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

* Except during startup and shutdown.

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

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

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

3. Definitions:

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

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

B. Upon commencement of operation of Unit #4, stack testing to demonstrate compliance with [~~the~~]each emission limitation[~~s~~] in IX.H.12.k.i.A and IX.H.12.k.i.A.IV 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~~]

[~~I~~]i. Kennecott Utah Copper: Smelter and Refinery

i. Smelter:

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

I. Main Stack (Stack No. 11)

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

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

3. NO_x 154 lbs/hr (daily average)

II. Holman Boiler

1. NO_x
   a. 14 lbs/hr, (calendar-day average)

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

EMISSION POINT	POLLUTANT	TEST FREQUENCY
I. Main Stack (Stack No. 11)	$PM_{2.5}$	Every Year
	SO_2	CEM
	NO_x	CEM
II. Holman Boiler	NO_x	Every three years and
		CEMS or alternate
	method	
according to		
		applicable NSPS standards

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

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

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

ii. Refinery:

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

EMISSION POINT	POLLUTANT	MAXIMUM EMISSION RATE
The sum of two (Tankhouse) Boilers	NO_x	9.5 lbs/hr (before December 2020)
(Upgraded Tankhouse Boiler)	NO_x	1.5 lbs/hr (After December 2020)
Combined Heat Plant	NO_x	5.96 lbs/hr

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

EMISSION POINT	POLLUTANT	TESTING FREQUENCY
Upgraded Tankhouse Boilers	NO_x	every three 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~~]k. Nucor Steel Mills

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

A. Electric Arc Furnace Baghouse

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

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

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

IV. VOC 22.20 lbs/hr

B. Reheat Furnace #1
NO_x 15.0 lb/hr

C. Reheat Furnace #2
NO_x 8.0 lb/hr

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

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

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

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

B. For $PM_{2.5}$ testing, 40 CFR 60, Appendix A, Method 5D, or another EPA approved method acceptable to the Director, shall be used to determine total TSP emissions. If TSP emissions are below the $PM_{2.5}$ limit, that will constitute compliance with the

$PM_{2.5}$ limit. If TSP emissions are not below the $PM_{2.5}$ limit, the owner/operator shall retest using EPA approved methods specified for PM2.5 testing, within 120 days.

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

[~~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~~]l. PacifiCorp Energy: Gadsby Power Plant

i. Steam Generating Unit #1:

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

51)

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

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

ii. Steam Generating Unit #2:

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

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

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

iii. Steam Generating Unit #3:

A. Emissions of NO_x shall be no greater than

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

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

B. Emissions of NOx shall not exceed

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

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

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

iv. Steam Generating Units #1-3:

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

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

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

B. <u>Emissions of NOx from each turbine stack shall not exceed 5 ppmvd (@ 15% O2 dry). Emissions shall be calculated on a 30-day rolling average. This limitation applies to steady state operation, not including startup and shutdown.</u>

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

vi. Combustion Turbine Startup / Shutdown Emission Minimization Plan

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

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

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

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

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

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

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

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

[~~o~~]m. 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~~]0.0019 lb/MMBtu
Condensable $PM_{2.5}$: [~~5.7 lb/MMscf~~]0.0056 lb/MMBtu

Plant gas:
Filterable $PM_{2.5}$: [~~1.9 lb/MMscf~~]0.0019 lb/MMBtu
Condensable $PM_{2.5}$: [~~5.7 lb/MMscf~~]0.0056 lb/MMBtu

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

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

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

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

Initial $PM_{2.5}$ stack testing on the FCC wet gas scrubber stack shall be conducted no later than January 1, 2019 and at least once every three (3) years 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)~~]emissions for each emitting unit shall be calculated by multiplying the hours of operation of a unit feed rate to a unit, or quantity of each fuel combusted at each affected unity by the associated emission factor, and summing the results.

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

ii. Source-wide NO_x Cap

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

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

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

Initial NO_x stack testing on natural gas/refinery fuel gas combustion equipment above 100 MMBtu/hr has already been performed and shall be conducted at least [~~once every three (3) years following the date of the last test~~]annually. At that time a new flow-weighted average emission factor in terms of: lbs/MMbtu shall be derived[~~for each combustion type listed in IX.H.12.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~~]0.0006 lb/MMBtu
Propane: EF = [~~0.60 lb/MMscf~~]0.0006 lb/MMBtu
Diesel fuel: shall be determined from the latest edition of AP-42

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

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

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

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

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

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

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

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

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

C. Instead of complying with Condition IX.H.11.g.ii.A, [~~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

52)

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

53)

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.

vi. No later than January 1, 2019, the owner/operator shall install the following to control emissions from the listed equipment:

54)

Emission Unit	**Control Equipment**
FCCU / CO Boiler	Wet Gas Scrubber, LoTOx
Furnace F-1	Ultra Low NOx Burners
Tanks	Tank Degassing Controls

North and South Flares	Flare Gas Recovery
Furnace H-101	Ultra Low NOx Burners
Truck loading rack	Vapor recovery unit
Sulfur recovery unit	Tail Gas Treatment Unit
API separator	Floating roof (single seal)

[~~p~~]n. The Procter & Gamble Paper Products Company

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

Source: Paper Making Boilers (Each)

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

Source: Paper Machine Process Stack

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

Source: Utility Boilers (Each)

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

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

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

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~~]o. University of Utah: University of Utah Facilities

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

Emissions Point	Pollutant	ppmdv (3% O_2 dry)
[~~Boilers #3~~]	[~~NO_x~~]	[~~18~~]7
Boiler[~~s~~] #4[~~a & 4b~~]*	NO_X	[~~9~~]187
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~~]p. Utah Municipal Power Association: West Valley Power Plant.

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

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

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

[~~ii~~]iv. 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 Standards 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).

60)

I. No later than the 28th of each month, a rolling 30-day VOC emission average shall be calculated for the previous month.

61)

62) 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.

63)

I. No later than the 28th of each month, the NO_x lb/hr emission total shall be calculated for the previous month.

64)

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.

ATTACHMENT B

Comments Submitted by EPA

H-1[submitted by EPA Region 8]: The BACT analyses within the Part H Technical Support Documents (TSDs) should provide adequate support for the conclusions and for the associated emission limitations and monitoring, recordkeeping and reporting (MRR) requirements found in the Part H SIP update. Several of the TSDs note the performance potential of a given control technology, but select a less stringent emission limitation than may be attainable by a given control technology. In other cases, the TSD does not discuss how the limit (if proposed) comports to the appropriate level of control. An example is the nitrogen oxide (NOx) limit resulting from the application of selective non-catalytic reduction (SNCR) at the Lhoist North America – Grantsville Facility, where it is unclear how the mass based limit (pounds per hour (lb/hr)) is representative of the appropriate level of control. An additional example: the boilers at ATK Promontory, where the analysis identifies 9 parts per million (ppm) NOx as achievable, while the proposed Part H limitation is 15 ppm NOx without further explanation. To assist in understanding the results of UDAQ's analysis, the EPA recommends presenting a table summarizing the BACT conclusions and the associated limits that are adopted into Part H. Where emission limitations differ from the level of control determined to be appropriate through the BACT analysis, provide a discussion supporting the selected emission limitation.

Response to H-1: UDAQ requested and received BACT analyses from the Major Sources located within the PM2.5 Serious Nonattainment boundary as required by 40 CFR 51, Subpart Z. The submittals provided a BACT discussion for all emission points; large (greater than 5 tons per year (tpy)) and small (equal to or less than 5 tpy). UDAQ recognizes that there were two circumstances where a performance potential of a given control technology is noted but a less stringent emission limitation is selected. This was the case specifically for Lhoist North America in selection of SNCR with a NOx control efficiency of up to 30% as the selected control option but a lower level of control was used to establish the Part H limitation. UDAQ also recognizes that there was a 25.11 MMBtu/hr boiler at ATK Promontory where the BACT analysis identified 9 ppm as NOx control while the proposed Part H limitation listed a 15 ppm limitation.

The commenter did not mention which sources in addition to Lhoist North America and ATK Promontory did not meet the necessary BACT requirements addressed specific to this comment. Therefore the following is provided in response to Lhoist North America and ATK Promontory.

ATK Promontory: The ATK Promontory TSD document discussed a 9 ppm NOx recommendation for the 25.11 MMBtu/hr boilers. The final Part H limitation presented for public comment listed a 15 ppm NOx limitation for one 25.11 boiler. UDAQ recognizes this error and has correct the Part H limitation to require ATK to upgrade both boilers to meet the 9 ppm NOx limitation as concluded in the BACT analysis.

Lhoist North America: *See comment response H-61: Comment 6.*

H-2[submitted by EPA Region 8]: The identification of technologically feasible controls should include a cost table outlining the economic feasibility, including the total capital costs, annual operating and maintenance costs, and the total annualized costs (including the necessary assumptions), as well as the assumed control efficiency and tons of pollutants reduced and cost effectiveness of the control (costs per ton pollutant reduced). In some instances, only the cost effectiveness is presented, which by itself may not provide sufficient information about the economic impact resulting from a control option. For situations where small pollutant reductions are projected (e.g., less than 1 ton) the cost effectiveness (i.e., cost per ton) may greatly exceed the total capital cost, as well as the total annualized cost. Therefore, to clearly disclose the economic impact of a control technology, please provide each cost estimate that goes into the computation of cost effectiveness. Additionally, when a control technology has benefits in reducing more than one pollutant the costs should be apportioned based on the benefit per ton of all pollutants that will be reduced by a single, or common, control technology (e.g., the cost of a common control device should be shared, or apportioned, to both $PM_{2.5}$ and sulfur dioxide (SO_2) for common controls, such as scrubbers or wet electrostatic precipitators). We are available to discuss a procedure for doing so in more detail.

Response to H-2: UDAQ recognizes the convenience of having a cost table outlining the economic feasibility, including the total capital costs, annual operating and maintenance costs, and the total annualized costs, as well as the assumed control efficiency and tons of pollutants reduced and cost effectiveness of the control all in a single table. The detailed information being requested is available in the source specific BACT submittals which were available for review during the comment period. Due to this information being available and coupled with the limited amount of time available for UDAQ to develop the TSD, tables were not generated. No changes were made to the TSD or Part H limits as a result of this comment.

H-3[submitted by EPA Region 8]: The EPA recommends that UDAQ consider structuring emission limitations as performance-based limits that are representative of proper operation of pollution controls. In many instances, the form of the emission limitation is expressed as a lb/hr emission rate with an averaging period less than or equal to 24-hours. The EPA commends Utah for structuring limits to be protective of the 24-hour PM2.5 NAAQS. However, BACT limits are most often expressed as a numeric limit indicative of good performance of a control technology on a continuous or short-term basis (e.g. rolling 24-hour average). These limitations are typically in the form of a short-term performance based limit (e.g. pounds of emission per million British thermal unit (lb pollutant/MMBtu) for boilers and fuel burning equipment, grains/dry standard cubic foot or material processed for baghouses that do not control fuel burning equipment, ppm for turbines (potentially in combination with a lb/hr limitation), and grams/brake horsepower-hr for engines (potentially in combination with a horsepower, heat input or fuel rate, or lb/hr limitation)). Further, the EPA recommends that UDAQ consistently document how the proposed limitations reflect proper operation of the best available level of control documented in the TSDs.

Response to H-3: UDAQ has re-evaluated emission limitations for the Part H sources and determined that many of the emission limits could be updated (i.e. converted from lbs/hr to the proper unit suggested by EPA for the equipment type as provided in Comment H-3). Therefore, all Part H sources are making changes in emission limitations to reflect the suggested form of short-term performance based limits; where applicable.

H-4[submitted by EPA Region 8]: The EPA recommends that UDAQ consider shortening stack testing frequency to once a year and/or providing additional means for ensuring emitting units and air pollution controls are operating as designed. There are many instances where stack testing is required once every 3 years. Examples include but are not limited to Big West Oil, Chevron Products Company, Compass Minerals Ogden, Tesoro Refining and Marketing Company, Procter & Gamble Paper Products Company, and the University of Utah. Such infrequent stack testing can allow poorly performing equipment to operate without detection for extended periods of time. Additionally, for sources that have not been tested and are not proposed to have periodic testing, we recommend considering methods to verify emission rates and the effectiveness of the control technology.

Response to H-4: UDAQ disagrees with this comment that UDAQ apply an annual test when stack testing is required. UDAQ has imposed a stack testing requirement of once every three years for all sources located in a nonattainment or maintenance area. UDAQ engineers determine stack testing frequencies by examination of how close a source is to a threshold (significance, PSD, etc.), what existing stack requirements are currently in place, and whether the equipment is controlled with industry wide accepted technology. For most operations where stack testing is appropriate, parametric monitoring is also performed to show the control equipment is operating properly. A review of stack testing records reveals that a stack test performed once every three years is sufficient for sources that lack variability in emissions.

With that stated; UDAQ has reviewed source testing data and determined that Big West Oil, Chevron Products Company, Holly Corp., Tesoro Refining and Marketing Company, Compass Minerals, and Lhoist North America shall implement annual stack testing due to variability in some emission sources. The appropriate sections of the Part H limitations for these sources have been updated to include an annual stack testing requirement.

H-5[submitted by EPA Region 8]: The EPA recommends clarifying stack testing frequency for the Lhoist North America - Grantsville Facility. IX.H.12.c requires compliance for the Grantsville Facility NO_x, PM and $PM_{2.5}$ limitations through stack testing. Stack testing protocols are outlined under IX.H.11.e, but do not dictate stack test frequency. As such, it is unclear how often stack testing is to be conducted for this source. In addition, we recommend clarifying that for sources that will use stack testing, the averaging period of the limit is that of the test (i.e., 3-hour average).

Response to H-5: UDAQ agrees with this comment for Lhoist North America. The following updates will be included in the Part H Limitations for Lhoist North America:

Lime Production Kiln

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

a. Effective January 1, 2019, or upon source start-up, whichever comes later, NO_X emissions shall not exceed 56.25 lb/hr.(3-hour average)

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

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

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

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

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

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

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

IX.H.c.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.

H-6[submitted by EPA Region 8 – Generic Refinery Comments]: UDAQ BACT analyses for refineries, and the emission limitations selected for the sector wide limits within the SIP, conclude that BACT is equivalent to the level of control attained by 40 CFR part 60 New Source Performance Standard (NSPS) for refineries. We recommend that UDAQ analyze all potential control technologies (including those considered by the EPA when promulgating the NSPS) and determine if emission levels lower than the applicable NSPS are appropriate. In so doing, we recommend considering the incremental cost of increasing control efficiency for a control option being considered.

Response to H-6: UDAQ disagrees with this comment. For the refineries, each source was reviewed in comparison to both a set of “Refinery General Requirements” – which encompass those conditions found in Section IX.H.11.g (subsections i through vii); as well as individually for BACT. The limitations and conditions imposed as individual BACT requirements are found under each source’s particular subsection of Section IX Part H.12. For example, each refinery is subject, at a minimum, to the refinery fuel gas sulfur requirements found in IX.H.11.g.ii.A – regardless of whether that refinery was previously subject to the requirements of 40 CFR 60 Subpart Ja or not. However, any particular refinery is then further limited by individual requirements found in Section IX.H.12. Consider the Chevron refinery, which has a combined SO2 emission limitation for all process equipment of 1.05 tons per day. Both the amount of fuel gas consumed and the amount of sulfur present in that fuel gas are monitored continuously (averaged for each one-hour period) For more specific replies to questions on individual control options please see the Response to Comment H-47 below.

H-7[submitted by EPA Region 8 - Generic Refinery Comments]: The EPA recommends UDAQ include more analysis to explain why a cost is not achievable for a particular source when control technologies are determined to be economically infeasible. Many of the discussions on refinery BACT identify the cost effectiveness of a control technology as economically infeasible without explaining what is feasible and what has been determined to be feasible in other similar situations. The analyses do not put forward any discussion on what cost has been determined to be economically infeasible, or if any analysis has been done beyond what the source presented in their submitted information.

Response to H-7: This comment appears to be searching for a presumptive BACT cost evaluation – a specific “dollar spent per ton of pollutant removed” which defines economic feasibility. UDAQ does not subscribe to the concept of presumptive BACT as each evaluation must always be considered on a case-by-case basis. For example, one particular source may already have made the business decision to install and operate an extremely expensive control option in order to advertise its “green” approach or environmental focus. A simple cost/ton analysis may yield a result of $100,000/ton. But this would not define economic feasibility, as a smaller, less wealthy company may be unable to afford to install under such an approach.

Instead, experience has shown in most cases that natural “break points” appear in the review of economic analyses. When the cost effectiveness values of various control options are listed together, typically the values appear to cluster together and that natural separations appear between these clusters; almost self-determining what is and is not economically feasible. To use an example from one of the Serious SIP BACT reviews:

After evaluation of the data submitted by PacifiCorp for the Gadsby Power Plant, UDAQ recalculated the control cost for NOx emissions from the Utility Boilers for several control options – SCR, SNCR, and FGR. Control costs ranged from $200K/ton for SCR, $100K/ton for SNCR, and $35K/ton for FGR (all for Boilers #1 and #2). While installation of SCR and SNCR were both immediately determined to be economically infeasible with control costs over $100K/ton; installation of FGR was not eliminated on an economic basis alone. What ultimately eliminated the installation of FGR was the combination of the low amount of emission reductions, the relatively high cost, and technical issues related to design and installation within the BACT window.

Although UDAQ does not subscribe to presumptive BACT, generally speaking, control costs above a designated amount can be considered economically infeasible. Although SIP BACT economic infeasibility ranges vary from location to location, the most expensive of these (San Joaquin Valley Air Pollution Control District – SJVAPCD), topped out at $25K/ton.

<u>Comments Submitted by Utah Petroleum Association</u>

H-8[submitted by Utah Petroleum Association (UPA)]: "Clean Air Act Authority to Control Emissions from Sources Outside the Salt Lake City Nonattainment Area", Baker Botts, July 26, 2018

Response to H-8: DAQ acknowledges that the Implementation Rule provides authority and direction to control emissions from sources located outside the NAA (but within the state) if necessary to provide for attainment by the attainment date. This authority also extends to PM2.5 plan precursors (those precursors required to be regulated in the applicable attainment plan and/or the NNSR program).
Nevertheless, the applicable attainment plan already demonstrates attainment of the standard by the attainment date. Therefore it is not necessary to extend control beyond the boundary of the nonattainment area.

H-9[submitted by UPA]: "Contributions to Salt Lake City $PM_{2.5}$ from Ammonium Chloride and Evidence for US Magnesium Corporation as its Significant Source", Ramboll, July 2018

Response to H-9: Chloride is not a plan precursor. The Implementation Rule does not presume that it is, and DAQ has no analysis that shows that it should be. That said, chloride is observed on collected filters where ammonium chloride can account for as much as 15% of the total PM2.5 mass. It remains unclear where the chloride on the DAQ filters collected in Salt Lake Valley may be coming from. Moreover, ammonium chloride is severely underestimated in DAQ's modeling. While U.S. Magnesium accounts for the important chloride contributors, chlorine and hydrochloric acid (HCl), the model does not transport these emissions westward across the Great Salt Lake into Salt Lake City. HCl and halogens emissions may also be underestimated in the model.
The commenter points to the preamble to the Implementation Rule which states that it "does not include any national presumption that would allow a state to exclude, without a demonstration, sources of emissions of a particular precursor from further analysis for attainment plan or NNSR control requirements in a PM2.5 nonattainment area" as if it provides a directive to address ammonium chloride. DAQ believes the context of this statement is important, so it is presented below:
For the purposes of this rule, the EPA considers that for all PM2.5 nonattainment areas, the PM2.5 precursors for regulatory purposes are the four scientific precursors that the EPA has previously identified: SO2, NOx, VOC and ammonia. This rule does not include any national presumption that would allow a state to exclude, without a demonstration, sources of emissions of a particular precursor from further analysis for attainment plan or NNSR control requirements in a PM2.5 nonattainment area. (81 FR 58019)

Clearly the statement applies to the four plan precursors, not to any of the other scientific precursors. The Ramboll analysis [attached as Doc.2 to the UPA Supplemental Comments] presents a weight-of-evidence analysis that clearly identifies ammonium chloride as a significant contributor to PM2.5 concentrations that exceed the National Ambient Air Quality Standard (NAAQS) in the Salt Lake City Serious Nonattainment Area, and indicates that US Magnesium Corporation is the single culpable source..

DAQ remains interested in pursuing some of the questions raised by the Wintertime Fine Particulate Study, among these questions is the attribution of ammonium chloride. However, it is not compelled by rule to include U.S. Magnesium in the SIP at this time.

H-10[submitted by UPA]: The first principal comment addresses UDAQ's proposal to impose additional controls on potential precursor emissions from major stationary sources even though the emissions of those precursors are shown to insignificantly contribute to PM2.5 levels and their control will not advance attainment.

Response to H-10: DAQ has reviewed Attachment A to Enclosure 1 of the UPA's comments. From this review, we would agree that the analysis has been conducted, in accordance with both the $PM_{2.5}$ Implementation Rule and the EPA's draft Precursor Demonstration Guidance. The comment anticipates that, were DAQ to conduct the same analysis, it too would reach the same conclusion. Still, DAQ would need to conduct an independent analysis before including it in the SIP, and in doing so would work, as we always do, with the regional modeling staff at EPA.

There are likely some things we would do somewhat differently, but given the conservative nature of the concentration based demonstrations, it appears that the conclusions would probably remain much the same. Furthermore, if they did not, 40 CFR 51.1006 still allows for a less conservative, sensitivity based analysis. The commenter is correct to note that DAQ has not elected to include any demonstration that any of the plan precursors identified in the Implementation Rule may be disregarded, whether comprehensively or only for major stationary sources, and the commenter is correct that DAQ could choose to do so.

One will certainly note in Chapter 6 of the SIP narrative, which discusses attainment of the standard by the attainment date, that there is much discussion concerning some of the shortcomings of the air quality model with regard to its sensitivity to reductions in precursor emissions. Presented along with that discussion is a weight of empirical evidence suggesting that a history of controlling precursor gasses has effectively mitigated the peak values of $PM_{2.5}$which occur in winter when secondary $PM_{2.5}$ causes exceedances of the NAAQS.

Some of the examples specifically cited in the Weight of Evidence discussion include:

- *Missing HCl and Cl from the Emissions Inventory:* This apparent underestimation in chloride and HCl emissions adds uncertainty to the modeling results. By not accounting for these emissions and their impact on $PM_{2.5}$ formation through the availability of various oxidants, the model's sensitivity to NOx controls may be limited.
- *Uncertainties in Ammonia Emissions:* Ammonia is a key precursor to ammonium nitrate, the predominant (up to 60%) $PM_{2.5}$ component during persistent wintertime inversion periods in northern Utah. While NOx emission sources are generally well understood, there are many uncertainties surrounding the origins and distribution of ammonia emissions.
- *Missing Nitryl Chloride Chemistry Pathway in CAMx:* Given $ClNO_2$'s role in contributing to the oxidants budget, an exclusion of this pathway in CAMx may increase the model's sensitivity to oxidants and may limit its sensitivity to NOx emissions. Without this pathway, the model may be less responsive to proposed NOx controls.
- *Misrepresentation of Formaldehyde in the Model:* The model's sensitivity to changes in NOx emissions may be obscured by an under-estimation of formaldehyde during mid-day hours. Both modeled ozone and nitrate (Figure 6.12) increased after increasing formaldehyde emissions, suggesting that the model may have a limited sensitivity to a reduction in NOx emissions.

When considered together, this should give one pause when interpreting results from the model that perhaps indicate it would be appropriate to exclude control of precursors at major stationary sources. The commenter is correct that the description of BACM / BACT as "generally independent" of the attainment demonstration does not mean that it is "entirely independent", and DAQ acknowledges the connection made between the two by such precursor demonstrations as have been presented in Attachment A. Ultimately, however, it is the EPA Administrator that would need to approve such demonstration(s) before the relevant precursors could be excluded from the control requirements required by 40 CFR 51.1010.

The Serious Area SIP, including both provisions to ensure BACT and the attainment demonstration, which shall include air quality modeling, are due to EPA at the same time. DAQ cannot know, at that time, whether EPA will approve the attainment demonstration and, by extension, any precursor demonstrations made a part thereof. The skepticism surrounding the air quality models' apparent insensitivity to reductions in precursor emissions influences DAQ's decision not to include such analyses in its demonstration.

These comments have been submitted, and are presently being addressed, in the context of the review of Part H. They have also been made part of the material to be reviewed which surrounds the remainder of the Serious Area SIP, including the attainment demonstration. As such, they will be addressed again after the conclusion of that comment period (Oct. 1 – Oct. 30) and before the remainder of the SIP is brought back to the Board for final adoption.

Should the Board determine that UPA's major stationary source precursor demonstration(s) should be made part of the modeling included in the attainment demonstration the petition for exclusion is effectively sent to EPA for its approval. In the meantime, specific measures in the proposed Part H affecting additional controls of such precursor emissions would, if approved by the Board, remain a matter of state law.

DAQ feels it is important to move forward with the BACT provisions. Aside from the procedural reasoning that the SIP is already behind the statutory due date for submittal, 2019 will be our attainment year. As such it is important to have a full suite of controls in place such that the monitored values collected may be as low as they can be.

In pursuit of that goal, Northern Utah continues to look at controls that would produce only marginal benefits. It has long been acknowledged that the "low-hanging fruit" has already been picked. The conclusion reached by the analysis in the comment was based on EPA's draft guidance, which identifies a threshold of 1.5 $\mu g/m^3$. As the AQB considers whether the controls on precursors may or may not be necessary, it might consider the appropriateness of this draft threshold to the unique circumstances present in Northern Utah. Ambient $PM_{2.5}$ in the SLC NAA airshed is largely composed of secondary $PM_{2.5}$ formed by precursors, not primary $PM_{2.5}$. In addition, as shown in the SLC NAA SIP, empirical evidence points to the success in declining concentrations of ambient $PM_{2.5}$ from controlling precursor emissions. This begs the question: is a major stationary source precursor demonstration for all four plan precursors appropriate for the SLC NAA?

Regardless, the intent of a precursor demonstration is to exclude precursors that do not significantly contribute to the formation of secondary $PM_{2.5}$ in the particular airshed and the demonstration is typically prepared and submitted by the local air quality agency. UDAQ would appreciate the opportunity to perform our own analysis, in consultation with the EPA, before approval of any precursor demonstration.

H-11[submitted by UPA]: UDAQ has failed to include control measures for residential wood combustion in its proposal that the State is legally obligated to adopt and which have the potential to make a very significant contribution to attaining and maintaining the 24-hour PM2.5 standard. This comment is also supported by a technical modeling report titled, Modeled Contributions of Residential Wood Combustion to PM2.5 in the Salt Lake City 24-hour PM2.5 Serious Nonattainment Area, which is attached as Attachment B to Enclosure No.1.

Response to H-11: The commenter's points are well taken, however BACM for Residential Wood Combustion (RWC) was not specifically part of the Part H proposal, which addresses BACT requirements for the major point source category.

BACM for all source categories is addressed in the remainder of the SIP (Section IX.A.31) that was just released for public comment. As such, DAQ will accept comments on the BACM analyses for area source rules, including RWC, during a separate comment period (Oct. 1 – Oct 30). These comments will be addressed following the conclusion of that period.

If, as a result of the comment period, changes become necessary to the BACM analysis, such revisions will become part of the TSD. In addition, further rulemaking involving R307-302 could be undertaken at any time.

Comments Submitted by ATK Launch Systems

H-12[submitted by Northrop Grumman (ATK Launch Systems)]: ATK has reviewed Part H.12.a. of the Plan regarding emission limitations for the Promontory plant. Part H.12.a.1 restricts emissions on open burning of reactive wastes. The limitation reads as follows:

"During the period November 1 to February 28/29 on days when the 24-hour average PM2.5 levels exceed 35 µg/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."

The limitation was drafted prior to finalization of the facility's Subpart X permit authorized by the federal Resource Conservation and Recovery Act (RCRA). The Subpart X permit was issued to the Promontory facility in 2016. The RCRA Subpart X permit and the facility's Clean Air Act (CAA) Title V permit authorize open burning of reactive wastes under the clearing index system. *Historically, the clearing index system is a more stringent parameter under which to conduct open burning. Therefore, the Promontory facility would like to align Part H.12.a limitations with limitations already established in the RCRA Subpart X permit and the CAA Title V permit.*

Response to H-12: The clearing index is used primarily for residential burning and in the RCRA permit. Restricting the open burning to data to the nearest real-time monitoring station data is directly related to the $PM_{2.5}$ standard. The existing Subpart H limitation will be retained.

H-13[submitted by Northrop Grumman (ATK Launch Systems)]: ATK has requested UDAQ to change the Part H.12.a limitation from: *"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.*

to read as follows;
"the open burning of reactive wastes with properties identified in 40 CFR 261.23 (a) (6) (7) (8) may be conducted when the 24-hour average PM2.5 levels exceed 35 ug/m3 at the nearest real-time monitoring station in limited quantities. Limited quantities, as authorized in the facility's RCRA Subpart X permit, of time-sensitive reactive wastes may be open burned when the 24-hour average PM2.5 levels exceed 35 ug/m3 at the nearest real-time monitoring station.

Response to H-13: UDAQ agrees with ATK and understands the safety issue involved with time-sensitive reactive waste. UDAQ will allow ATK to dispose of time-sensitive waste material in limited quantities. The following are the definition of terms in the limitation.

Time-Sensitive Materials (TSM) or Time-Sensitive Explosive Waste
Wastes material that has short storage times (7 to 30 days) with decreased stability and the potential for high energy release. 40 CFR Part 264, Subpart X provides a regulatory avenue for treatment, storage, and/or disposal of unique waste streams in miscellaneous units. Miscellaneous units must meet specific requirements to ensure protection of human health and the environment.

In the interests of safety, these time-sensitive wastes materials require treatment when meteorological conditions are not always ideal. These wastes are uncured propellants or precursors containing ingredients such as nitroglycerine (NG) that can be absorbed by adjacent materials (e.g. rags, wipes, fiberboard container, etc.). When NG is released from propellants, absorbing onto adjacent material, an unsafe and unstable condition is created.

Limited Quantities

During times when the 24-hour average PM2.5 levels exceed 35 µg/m3 at the nearest real-time monitoring station, open burning of limited quantities of Time-Sensitive Materials (TSM) can be conducted in two scenarios to protect human health and the environment:

Scenario 1 — 1,000 pounds of TSM can be open burned when the 24-hour average PM2.5 levels exceed 35 µg/m3 when the minimum wind speed is below 3 miles per hour; and

Scenario 2 — 1,500 pounds of TSM can be open burned when the 24-hour average PM2.5 levels exceed 35 µg/m3 when the minimum wind speed is above 3 miles per hour.

Therefore, open burning of limited quantity TSM is 1,000 lbs. when no favorable meteorological conditions are present or 1,500 lbs. if a minimum wind speed of 3 miles per hour is reached.

<u>Comments Submitted by Big West Oil LLC</u>

H-14[submitted by Big West Oil (BWO), LLC]: The PM SIP inappropriately proposes to apply certain requirements of U.S. EPA's New Source Performance Standards for Petroleum Refineries, codified in 40 C.F.R., Part 60, Subpart Ja ("NSPS Ja"). Specifically, Subsections IX.H.l.g.i.A.II and IX.H.ll.g.i.A.II require demonstration of compliance with the Fluid Catalytic Cracking Units (FCCU) SO2 limit in accordance with 40 C.F.R. section 60.105a(g). In addition, Subsections IX.H.1.g.i.B.III and IX.H.11.g.i.B.III require that FCCU install and operate continuous parameter monitoring system (CPMS) in accordance with 40 C.F.R. section 60.105a(b)(1).

BWO is subject to NSPS Subpart J ("NSPS J"), not NSPS Ja. Imposing NSPS Ja in this regard is inappropriate as these provisions require implementation of costly monitoring equipment without any corresponding reduction in particulate matter emission. Though the emission limits for a FCCU under NSPS J and NSPS Ja are the same for particulate matter, O2 and SO2, NSPS Ja requires extensive monitoring equipment while NSPS J emission are determined in accordance with prescribed stack tests, a method that Subsection IX.H.2.d.1.A of the rule endorses. (*see BWO suggested language)*

Response to H-14: UDAQ agrees with this comment. There are currently four refineries subject to this requirement, and each is slightly different. After reviewing all of the suggested changes to the language of this requirement, and taking into account the particular nuances in physical configurations at each refinery, UDAQ has opted for the following revised wording, which will appear in the two listed general requirements sections of the SIP.

Subsection IX.H.1.g.i.B.III

No later than January 1, 2019, each owner or operator of an FCCU subject to NSPS Ja shall install, operate and maintain a continuous parameter monitor system (CPMS) to measure and record operating parameters from the FCCU for determination of source-wide particulate emissions as per the requirements of 40 CFR 60.105a(b)(1). No later than January 1, 2019, each owner or operator of an FCCU not subject to NSPS Ja shall install, operate and maintain a continuous opacity monitoring system to measure and record opacity from the FCCU as per the requirements of 40 CFR 63.1572(b) and comply with the opacity limitation as per the requirements of Table 7 to Subpart UUU of Part 63.

Subsection IX.H.11.g.i.B.III

No later than January 1, 2019, each owner or operator of an FCCU subject to NSPS Ja shall install, operate and maintain a continuous parameter monitor system (CPMS) to measure and record operating parameters for determination of source-wide PM2.5 emissions as per the requirements of 40 CFR 60.105a(b)(1). No later than January 1, 2019, each owner or operator of an FCCU not subject to NSPS Ja shall install, operate and maintain a continuous opacity monitoring system to measure and record opacity as per the requirements of 40 CFR 63.1572(b).

The differences between the two subsections are specific to the type of particulate and nonattainment area in question for each subsection. Holly Frontier, which operates WGS systems on both FCCUs at its facility, will have specific language inserted into sections IX.H.2.f.i.A and IX.H.12.g.i.A to address the inability to measure opacity at WGS controlled Subpart J compliant FCCUs. That language is as follows:

… As an alternative to a continuous parameter monitor system or continuous opacity monitoring system for PM emissions from any FCCU controlled by a wet gas scrubber, as required in Subsection IX.H.1.g.1.B.III (alt. IX.H.11.g.i.B.III), the owner/operator may satisfy the opacity monitoring

requirements from its FCC Units with wet gas scrubbers through an alternate monitoring program as approved by the EPA and acceptable to the Director.

H-15[submitted by BWO, LLC]: Subsections IX.1.g.i.B.I and IX.H.l1.g.i.B.I provide for a particulate matter emission limit for FCCUs of 1.0 pounds of PM per 1,000 pounds of coke burned on a "3-hour average basis". This language suggests that compliance with the limit is required in a continuous 3-hour average basis. Under NSPS J or Ja it is required that compliance with the 1.0 pounds of PM per 1,000 pounds of coke burned limit be determined in accordance with the stack test protocol provided in NSPS J or NSPS Ja. These stack tests protocols under NSPS J or NSPS Ja set forth the specific parameters for both the number and length of each test that must be satisfied in order to conduct a valid test which will not allow PM emissions to be determined in a continuous or rolling 3-hour average.

Duration limits and calculation methods under Subsection IX.H.l.g.i.B.II and IX. H.ll.g.i.B.I, contrary to requirements under NSPS J and NSPS Ja, which are expressly required by Subsections IX.H.l.g.B.II and IX.H.ll.g.i.B.II, would make compliance with both provisions of the PM SIP impossible. With no technical basis as to why UDAQ feels that a 3-hour average basis is either necessary or appropriate (*see BWO suggested language)*

Response to H-15: UDAQ agrees with this comment. The stack test in both sections is being changed to once every three years, as per the specific protocol specified in the NSPS. Compliance will be validated with CPMS or COMs as per the provisions of IX.H.1.g.i.B.III or IX.H.11.g.i.B.III (see also UDAQ’s response to H-14).

<u>Comments Submitted by Chevron Products Company</u>

H-16[submitted by Chevron Products Company]: References to Compressor Engines Should Be Consistent with DAQ Administrative Order.

There are three (3) 391 horsepower 4-stroke rich burn spark ignition reciprocating internal combustion engines ("RICE") located at the Salt Lake Refinery. These engines are identified as K35001, K35002, and K35003 in the Refinery's Administrative Order ("AO") issued by DAQ. The AO sets forth the *same* NOx emission limits for these RICE as is set forth in Subsections IX.H.2.d.v.A and IX.H.l2.d.v.A of the PM SIP. However, Subsections IX.H.2.d.v.A and IX.H.12.d.v.A refer to these engines as "Engine Number 1, 2, and 3" instead of"K35001, K35002, and K35003". To avoid any ambiguity between these subsections of the PM SIP and the AO regarding these RICE, we request that Subsections IX.H.2.d.v.A and IX.H.12.d.v.A be revised as follows: (*see proposed language)*

Response to H-16: UDAQ agrees with this comment. The referencing on the listed equipment will be updated to use the suggested "K35001" through "K35003" values.

H-17[submitted by Chevron Products Company]: Method for Calculating Compliance with Flare Flow Requirements Should Be Consistent for PM2.5 and PM10

As DAQ is aware, the PM SIP requirements regarding the PM10 Nonattainment/Maintenance Area and the PM2.5 Nonattainment/Maintenance Area largely mirror one another. While these provisions are nearly identical, there are instances in which these provisions are inconsistent or incorrect, and thus, should be appropriately corrected. First, Subsection IX.H.1.g.v., which provides the general requirements for hydrocarbon flares located in the *PM10* Nonattainment/Maintenance Area, references hydrocarbon flares at petroleum refineries located in or affecting a *PM2.5* non-attainment area in Utah. The reference to "PM2.5" instead of "PM10" in Subsection IX.H.l.g.v appears to be in error and should therefore be revised as follows (which reflects acceptance of the other DAQ-proposed changes to this provision): (*see proposed language)*

Response to H-17: UDAQ agrees with the intent of this comment, in that the language of both sections should be consistent. When the requirement was originally drafted, during development of the moderate PM2.5 SIP, it was unknown at that time what the final state of the PM10 nonattainment area would be as the various SIP processes went forward. As the majority of the past and present SIP-listed refineries are physically located outside the boundaries of the PM10 nonattainment area, the intent was to ensure that the general requirements for hydrocarbon flares would continue to apply to all refineries which may have an impact on either the PM10 or PM2.5 nonattainment or maintenance areas. This was later changed to only apply to major source refineries based on the language found in Subpart Ja. In the interest of avoiding potentially confusing language, UDAQ simply chose to reference the PM2.5 nonattainment (or maintenance) areas since these areas encompass the entirety of the PM10 nonattainment (or maintenance) areas[1]. However, UDAQ was not consistent in this approach, and used more precise language in other sections. Therefore, UDAQ will update the PM10/PM2.5 language to read as follows:

… petroleum refineries in or affecting any PM2.5 nonattainment area or any PM10 nonattainment or maintenance area …

Some requirements are still applicable to all refineries regardless of source size (i.e. major source or minor source status) while others are applicable to major sources only. It is not the intent of this language

[1] With one exception being a small section of Utah County and located in the far southeast corner of that county.

clarification to change this applicability, only to establish that the requirements apply in both PM10 and PM2.5 areas.

As for the second part of the commenter's request – the inclusion of new subsection IX.H.2.d.vi.A (see Chevron proposed language), UDAQ agrees that this request is valid. UDAQ intended to include the same language prior to public comment, but it was accidentally left out.

H-18[submitted by Chevron Products Company]: Application of U.S. EPA NSPS Ja Provisions to the Salt Lake Refinery is Inappropriate

The PM SIP inappropriately proposes to apply certain requirements of U.S. EPA's New Source Performance Standards for Petroleum Refineries, codified in 40 C.F.R., Part 60, Subpart Ja ("NSPS Ja"). Subsections IX.H.l.g.i.A.II and IX.H.ll.g.i.A.II require demonstration of compliance with the Fluid Catalytic Cracking Units ("FCCU") SO2 limit in accordance with 40 C.F.R. section 60.105a(g). In addition, Subsections IX.H.l.g.i.B.III and IX.H.ll.g.i.B.III require that FCCU install and operate continuous parameter monitoring system ("CPMS") in accordance with 40 C.F.R. section 60.105a(b)(l).

Imposing NSPS Ja in this regard is inappropriate as these provisions require implementation of costly monitoring equipment without any corresponding reduction in particulate matter emission. Specifically, FCCUs at the Salt Lake Refinery are subject to 40 C.F.R., Part 60, Subpart J ("NSPS J"), not NSPS Ja. As a result, these facilities would incur potentially large capital costs and need to implement extensive operating changes required by NSPS Ja. For example, 40 C.F.R 60.105a(b)(l) requires an outlay of considerable resources to install, operate and maintain a CPMS. Importantly, however, deployment of such extensive monitoring equipment will have *no* corresponding reduction of particulate matter emissions, as particulate matter and SO2 emission limits for FCCU are the *same* under NSPS J and Ja. While NSPS Ja requires extensive monitoring equipment, particulate matter emissions are determined under NSPS J in accordance with prescribed stack tests, a method clearly endorsed under other provisions of the Rule. Further, NSPS Ja requires control device parameter monitoring for which the Salt Lake Refinery has no corresponding operating limit. It simply makes no sense to monitor a parameter for which there is no corresponding operating limit.

The *ad hoc* application of certain NSPS Ja provisions in this regard to the Salt Lake Refinery, which is not subject to NSPS Ja (only NSPS J)-without any associated reductions in particulate matter emissions-is arbitrary and capricious. In light of these concerns, these provisions should be revised as follows: (*see proposed language)*

Response to H-18: UDAQ agrees with this comment. This is essentially the same comment also submitted by another commenter although with slightly different wording and a different suggested resolution. As there are four listed refineries potentially affected by any change in the language of this requirement, UDAQ needed to consider all comments. Please see UDAQ's response to comments H-14 and H-15 for details on the final resolution of this matter.

H-19[submitted by Chevron Products Company]: Chevron Salt Lake Refinery PM2.s SIP Evaluation Report

"We have identified numerous factual and other errors in the Salt Lake Refinery PM2.s SIP Evaluation Report that should be corrected. (*see Table provided for errors and proposed corrections)"*

Response to H-19: UDAQ agrees with the errors pointed out by the commenter. The following corrections listed below should be used in conjunction with the Chevron Salt Lake Refinery PM2.5 SIP Evaluation Report:

Page 1, Section 1.2, Chevron operates one FCCU not two as listed.
Page 2, Section 1.3, the bullet point is out of place.
Page 2, Section 1.3, Chevron operates two Tail Gas Treatment Units, Tail Gas Incinerators (TGU/TGI) one controlling each SRU.
Page 2, Section 1.4, Table 2 should reference PM2.5 instead of PM10.
Page 3, Section 2.0, The AO incorporated consent decree required NOx limits on the reformer compressor drivers.
Page 5, Section 4.0, Chevron will replace boilers #1, #2, and #4 with new boiler #7. The work is still in process and has not been completed as was implied.
Page 11, Section 5.1.3, Minor typographical error
Page 15, Section 5.3.3, Chevron's current limit on NOx is 57.8 ppm not 59 ppm as listed.
Page 17, Section 6.1, the effluent gases from the two SRUs are sent to the two TGU/TGI units not to a single TGU/TGI.
Page 22, Section 11.1.3, Chevron implemented flare gas recovery on its hydrocarbon flares, Flare 1 and Flare 2. Chevron does not have a "North" or "South" flare.
Page 25, Section 12.3.3, Chevron sends VOC emissions from the WWTP to an RTO, so use of carbon canisters is technically infeasible.
Page 26, Section 12.3.3, As Chevron already operates two TGU/TGIs, the sentence on cost evaluation for additional controls should only reference WGS. Specifically: "The costs for WGS on the SRU do not currently justify including this control as MSM."

<u>Comments Submitted by Tesoro Refining & Marketing Company</u>

H-20[submitted by Tesoro Refining & Marketing Company]: COMMENTS ON: H.1 – GENERAL REQUIREMENTS: CONTROL MEASURES FOR AREA AND POINT SOURCES, EMISSION LIMITS AND OPERATING PRACTICES, PM10 REQUIREMENTS (*see specific source provided comments on H.1)*

Response to H-20: The commenter provided several suggested edits to specific subsections of IX.H.1. In general, these suggestions were provided to add clarity or to correct minor inconsistencies in the testing and monitoring requirements applicable to both refineries and other listed sources. UDAQ agrees with these corrections and has incorporated the suggested changes into the language of Section IX.H.1 – with the following exceptions:

In the suggested change for IX.H.1.e.i.B, the commenter has removed the language "acceptable to the Director." The suggested new language to be added prior to IX.H.1.e.i.C, is also missing this language. The comment states that "all EPA-approved testing methods should be considered acceptable to the Director." It is not the intent of that phrase to imply that the Director would not find an EPA-approved testing method acceptable generally. Rather, when the source wishes to use a testing method to demonstrate compliance with a particular emission limit found in IX.H.2 or IX.H.3, the choice of testing method must be acceptable to the Director as well as being an EPA-approved testing method. The language "acceptable to the Director will not be removed, and will be included with the suggested change added prior to IX.H.1.e.i.C.

UDAQ agrees with this comment. This is essentially the same comment also submitted by another commenter although with slightly different wording and a different suggested resolution. As there are four listed refineries potentially affected by any change in the language of this requirement, UDAQ needed to consider all comments. Please see UDAQ's response to comments H-14 and H-15 for details on the final resolution of this matter.

The suggested changes for IX.H.1.g.ii.A and IX.H.1.g.v.A are the same as that found in Comment H-17 provided by Chevron above. Please see the response to that comment.

H-21[submitted by Tesoro Refining & Marketing Company]: COMMENTS ON: H.2.K SOURCE SPECIFIC EMISSION LIMITATIONS IN SALT LAKE COUNTY PM10 NONATTAINMENT/MAINTENANCE AREA FOR TESORO REFINING & MARKETING COMPANY *(see specific source provided comments on H.2.K)*

Response to H-21: The commenter provided several suggested changes to the language of IX.H.2.K. Unlike the more general suggestions of Comment H-20, these changes would affect only the requirements applicable to the Tesoro Refining & Marketing Company refinery. Individual responses follow:

UDAQ agrees with the suggested change in the language of IX.H.2.k.i.A. The conversion of the emission factors does not change the assumed emission limits and adds clarity to the requirement. UDAQ has changed the language of IX.H.2.k.i.A as suggested.

UDAQ agrees with the suggested addition to IX.H.2.k.i.B. The additional language clarifies the original intent of the requirement, which was to allow for all stack testing to be used for setting of PM10 emission factors.

For IX.H.2.k.i.C the commenter provided two suggestions to correct the language of this requirement. The first option would be to convert the listed emission factors in a similar manner to IX.H.2.k.i.A. The second option would be to change the language to match the wording used in IX.H.2.k.ii.C – the compliance section for NOx. UDAQ prefers this second approach, as it is less reliant on a specific equation format, but instead lists the process generally and inclusively.

UDAQ agrees with the suggested change to IX.H.2.k.ii.B. The provided change adds clarity to the requirement. The language of IX.H.2.k.ii.B will be updated as suggested.

UDAQ agrees with the suggested change to IX.H.2.k.iii.A. The conversion of the emission factors does not change the assumed emission limits and adds clarity to the requirement. UDAQ has changed the language of IX.H.2.k.iii.A as suggested.

UDAQ agrees with the suggested change to IX.H.2.k.iii.C. The addition of the SRU to the list of sources clarifies the intent of the requirement to include all SO2 sources in the plant-wide limit.

UDAQ agrees with the removal of the duplicated language in IX.H.2.k.iv.B. The suggested change will be made.

H-22[submitted by Tesoro Refining & Marketing Company]: COMMENTS ON: H.11. GENERAL REQUIREMENTS: CONTROL MEASURES FOR AREA AND POINT SOURCES, EMISSION LIMITS AND OPERATING PRACTICES, PM2.5 *(see specific source provided comments on H.11)*

Response to H-22: The commenter provided several suggested edits to specific subsections of IX.H.11. In general, these suggestions were provided to add clarity or to correct minor inconsistencies in the testing and monitoring requirements applicable to both refineries and other listed sources. UDAQ agrees with these corrections and has incorporated the suggested changes into the language of Section IX.H.11 – with the following exceptions:

UDAQ agrees with the suggested changes to requirement IX.H.11.d.ii. There are no PM10 specific requirements in IX.H.12 or IX.H.13, (or any other section of the PM2.5 portion of the SIP, other than the specific listings found within IX.H.11 itself which are being kept for consistency with IX.H.1).

The commenter also suggested deleting requirement IX.H.11.e.i.D as these testing requirements apply to PM10 and IX.H.11 represents the PM2.5 general requirements section of the SIP. UDAQ agrees with this deletion, as there are no limitations found in Sections IX.H.12 and H.13 that remain based on PM10.

The suggested changes to IX.H.11.e.i.E are rejected. The first half of the suggestion, to remove the "acceptable to the Director" phrase, has been addressed in UDAQ's response to Comment H-20, suggested change to IX.H.1.e.i.B above. The second part of the suggestion, regarding "back half condensables" has been retained. Although the phrase is not specifically mentioned in the language of Method 202, it has been retained in the common parlance of stack testing when referring to condensable particulate matter.

The suggested edit for IX.H.11.g.i.B.III – UDAQ agrees with this comment. This is essentially the same comment also submitted by another commenter although with slightly different wording and a different suggested resolution. As there are four listed refineries potentially affected by any change in the language of this requirement, UDAQ needed to consider all comments. Please see UDAQ's response to comments H-14 and H-15 for details on the final resolution of this matter.

The suggested change to IX.H.11.g.ii.A is the same as the suggested change in comment H-17 regarding the choice of PM10 or PM2.5 nonattainment area. UDAQ will apply the same correction here to maintain the consistency of requirement language. Thus, the phrase in question will be updated to refer to:

… petroleum refineries in or affecting any PM2.5 nonattainment area or any PM10 nonattainment or maintenance area …

For further details please see UDAQ's response to Comment H-17 above.

UDAQ agrees with the suggested change to IX.H.11.g.iii.A. The applicability date has passed, meaning all referenced sources are subject to the requirement.

H-23[submitted by Tesoro Refining & Marketing Company]: COMMENTS ON: H.12. SOURCE-SPECIFIC EMISSION LIMITATIONS IN SALT LAKE CITY- UT PM2.5 NONATTAINMENT AREA FOR TESORO REFINING AND MARKETING COMPANY: SALT LAKE CITY REFINERY *(see specific source provided comments on H.12)*

Response to H-23: The commenter provided several suggested changes to the language of IX.H.12.o. Unlike the more general suggestions of Comment H-22, these changes would affect only the requirements applicable to the Tesoro Refining & Marketing Company refinery. Individual responses follow:

UDAQ agrees with the suggested change in the language of IX.H.12.o.i.A. The conversion of the emission factors does not change the assumed emission limits and adds clarity to the requirement. UDAQ has changed the language of IX.H.12.o.i.A as suggested.

For IX.H.12.o.i.C the commenter provided two suggestions to correct the language of this requirement. The first option would be to convert the listed emission factors in a similar manner to IX.H.12.o.i.A. The second option would be to change the language to match the wording used in IX.H.12.o.ii.C – the compliance section for NOx. UDAQ prefers this second approach, as it is less reliant on a specific equation format, but instead lists the process generally and inclusively.

UDAQ agrees with the suggested change to IX.H.12.o.ii.B. The provided change adds clarity to the requirement. The language of IX.H.12.o.ii.B will be updated as suggested.

UDAQ agrees with the suggested change to IX.H.12.o.iii.A. The conversion of the emission factors does not change the assumed emission limits and adds clarity to the requirement. UDAQ has changed the language of IX.H.12.o.iii.A as suggested.

UDAQ agrees with the suggested change to IX.H.12.o.iii.B. The addition of the SRU to the list of sources clarifies the intent of the requirement to include all SO2 sources in the plant-wide limit.

UDAQ agrees with the removal of the duplicated language in IX.H.12.o.iv.B. The suggested change will be made.

H-24[submitted by Tesoro Refining & Marketing Company]: COMMENTS ON: UDAQ'S $PM_{2.5}$ SERIOUS SIP EVALUATION REPORT FOR THE TESORO REFINERY (DAQ-2018-007379) *(see source provided comments in Section V)*

Response to H-24: The commenter provided several updates correcting various aspects of the assumptions used by UDAQ during its development of the technical support documentation (TSD) for the SIP (PM2.5 SIP Evaluation Report: Tesoro Refining & Marketing Company LLC). As some of these corrections are based on facts not presented to UDAQ at the time of preparation of the (TSD), UDAQ acknowledges that the final conclusions reached may not represent BACT in these cases.

Therefore, UDAQ supplies this updated analysis based on a combination of the new information and that information already listed as references in the original TSD.

- Section 9.1 VOC – BACT for Wastewater System

  The commenter provided additional information which further clarified the operation of the wastewater treatment system which was not included during the initial BACT analysis submittal (received May 5, 2017) or in the revised BACT analysis (received December 11, 2017). The system uses an API OWS (American Petroleum Institute oil water separator) with floating covers and single seals, which are being upgraded to double wiper seals. Tesoro did provide information regarding the economic feasibility of add-on controls such as RTO or carbon adsorption to the API OWS in the initial December 2017 BACT Analysis submittal which demonstrated a cost of effectiveness of approximately $200,000/ton.

  While UDAQ disagrees that the final cost of carbon adsorption would approach $200,000/ton even with this new information, it does agree that the use of floating covers would significantly increase the cost associated with capturing VOC emissions from the OWS. Floating covers do not lend themselves to the permanent installation of duct work and capture hoods as would a fixed cover. Given the limited amount of additional analysis possible during the response to comments period, UDAQ is willing to accept the commenter's assertion as to costs with reservations. UDAQ agrees that additional add-on controls, such as RTO or the use of carbon canisters are economically infeasible and are eliminated from further consideration as BACT. UDAQ recommends that the use of the existing API OWS with floating covers be retained as BACT. The floating covers should be replaced with double wiper seal-style floating covers no later than December 31, 2019, but this date is past the regulatory attainment date. Only "partial credit" can be taken for this control system – representing those controls in place by December 31, 2018.

- Section 12.0 BACT for Loading/Offloading

  The commenter provided additional information which further clarified the activities at the TLR (truck loading rack) and BCLR (blending component loading rack). UDAQ agrees with the comment. It was the intention of section 12 of the technical support documentation (TSD) to address controls for both loading and offloading processes – including all emission units capable of such activities. However, by consolidating all smaller emitting units under the umbrella of the BACT Review for Small Sources, this removed all offloading processes from further review in section 12. The language should have been updated to reflect this change. The TLR and BCLR are only used for loading activities at the refinery.

<u>Comments Submitted by Compass Minerals</u>

H-25[submitted by Compass Minerals]: The Emission Rate for BH-001 Should Be Amended from 0.27 lb/hr to 0.42 lb/hr to Correct a Calculation Error in the BACT Analysis Report.

The emission rate for BH-001 should be 0.42 lb/hr, and not 0.27 lb/hr. A conversion error was made in Table 7.1 of the BACT analysis report for BH-001 when converting from tons per year to pounds per hour. The sources controlled by BH-001 include Compass Minerals' Sulfate of Potash ("SOP") trucks and rail loading equipment, which are limited to 5,600 hours of operation per year and not, as incorrectly reflected in the report, 8,760 hours per year. As a result, the PM2.5-Fil limit proposed in Table 7.1 is incorrect. When calculated correctly, the rate for BH-001 should have been 0.42 lb/hr.

This information was communicated between Mr. John Jenks at UDAQ and Compass Minerals on May 17, 2018. However, the Board packet had already been prepared and dispersed by the time Compass Minerals had communicated the error to UDAQ, and the public comment period became the appropriate time to raise this issue. Accordingly, Compass Minerals hereby requests that the Board amend the emission rate for BH-001 from 0.27 lb/hr to 0.42 lb/hr in Section H.12(e)(iii) of the Proposed Revision to correct the calculation error made in the original submission.

Response to H-25: UDAQ received an updated emissions evaluation with suggested limits from Compass Minerals on September 11, 2018. The new evaluation has resulted in an emission limit that does not correspond to the comment above, but instead reflects this new update. The new emission limit is listed in Table 1 of response to comment H-64.

H-26[submitted by Compass Minerals]: Naming Conventions Should Be Updated For Consistency

At this time, we request that UDAQ update the naming conventions in Section IX, Control Measures for Area and Point Sources, Part H. e. to reflect the following: The "SOP Plant Compaction Building Baghouse" should be changed to "BH-1516" and "BH-1545" should be changed to "BH-008". Making these changes in the documents will assure consistency and avoid future confusion.

Response to H-26: UDAQ agrees with this comment. Equipment name changes were made to the Part H limits to assure consistency with all future documents, these changes are reflected in Table 1, found in the response to comment H-65.

H-27[submitted by Compass Minerals]: The Emissions Limitation for Magnesium Chloride Evaporators Should Be Removed Because It Is Not Adequately Supported.

The emission limitation for Magnesium Chloride Evaporators is arbitrary and should be removed. In the $PM_{2.5}$ Serious SIP Evaluation Report for Compass Minerals, UDAQ determined that no controls are technically feasible for Magnesium Chloride Evaporators and made no selection of BACT. *See* Utah Div. Air Quality, *$PM_{2.5}$ Serious SIP Evaluation Report: Compass Minerals – Compass Minerals Ogden*, at 13.3–.5 (July 1, 2018). Despite this conclusion, UDAQ recommended a VOC emission limitation of 9.27 lb/hr for Magnesium Chloride Evaporators. Because there are no viable control options for these sources, this emission limitation does not represent BACT and should, be removed from the Proposed Revision of the SIP.

The Clean Air Act ("CAA") defines BACT as an emission limitation that, on a case-by- case-basis, is determined to be "*achievable* for a facility through application of production processes and available methods, systems, and techniques . . . ." 42 U.S.C. § 169(3) (emphasis added). To fulfill this statutory requirement, the NSR Manual provides a step-by-step BACT analysis for permitting authorities to use when issuing an emission limitation for a particular source. *See generally* U.S. EPA, Office of Air Quality Planning & Standards, *New Source Review Workshop Manual* (draft Oct. 1990) ("NSR Manual"). These steps include "(1) identifying all available control options for a targeted pollutant; (2) analyzing the control options' technical feasibility; (3) ranking feasible options in order of effectiveness; (4) evaluating their energy, environmental, and economic impacts; and (5) selecting as BACT a pollutant emission limit achievable by the most effective control option not eliminated in a preceding step." *In re Newmont*, at 435; NSR Manual, B.5-.9. An adequate BACT analysis ensures that emission limitations are not only defensible but appropriately imposed. *See In re Knauf Fiber Glass, GMBH*, 8 E.A.D. 121, 129 n.14 (1999).

The emission limitation for Magnesium Chloride Evaporators has been determined without a supporting BACT analysis. UDAQ conducted Steps 1 through 4 of the BACT analysis pursuant to the NSR Manual. *See* Utah Div. Air Quality, *PM2.5 Serious SIP Evaluation Report: Compass Minerals*, at 13.1–.4. However, upon finding that no control options were technically feasible, UDAQ arbitrarily imposed an emission limit despite the inability to select BACT pursuant to Step 5 of the BACT analysis. Further, UDAQ has not made the required demonstration that the emission limitation is achievable pursuant to the CAA. *See In re Knauf*, at 129 n.14 ("We would not reject a BACT determination simply because the permitting authority deviated from the NSR Manual, but we would scrutinize such a determination carefully to ensure that all regulatory criteria were considered and applied appropriately."). Because this determination is not adequately supported as BACT, the 9.27 lb/hr emission limitation for Magnesium Chloride Evaporators is arbitrary and should be removed from the Proposed Revision.

Additionally, inclusion of specific emission limitations for this small source is counterproductive and inconsistent. Compass Minerals understands the importance of including enforceable emission limitations in the plan to assure attainment. However, the Magnesium Chloride Evaporators at the Ogden facility are a small source component of a larger regulated source, and attainment is not dependent on limiting these emissions. As articulated in the $PM_{2.5}$ Serious SIP Evaluation Report for Compass Minerals, there are no other sources with similar processes located in the United States, and, therefore, "VOC mitigation and investigations are ongoing." Utah Div. Air Quality, *$PM_{2.5}$ Serious SIP Evaluation Report: Compass Minerals*, at 13.5. Imposing an emission limit in the SIP for this source where the Evaluation Report clearly shows that control options are still being evaluated may hinder UDAQ's ability to adequately investigate appropriate control options for this source in future permitting actions.

Compass Minerals is proposing to incorporate the Magnesium Chloride Evaporators into its Approval Order ("AO") currently under review at UDAQ. In past SIP processes, UDAQ has taken the position that it would "not put requirements in the SIP that become antiquated as new federal limits are implemented or has new monitoring methods become available." *See* Utah Div. Air Quality, *PM2.5 Sections IX.A.21, IX.A.22, IX.A.23 and SIP Sections IX.H.11, 12 and 12: Comments and Responses to Comments Made During the October 2014 Public Comment Period*, at 15 (Nov. 19, 2014). We believe that including a VOC emission limit on the Magnesium Chloride Evaporators in the SIP is unnecessary, creates a potential future burden for both UDAQ and Compass Minerals, and is inconsistent with UDAQ's stated policy in the development of previous SIPs.

Response to H-27: UDAQ disagrees with this comment. The commenter has pointed out that an evaluation has been performed and no available control options were found to be technically or economically feasible. A functional limit on production provided by Compass Minerals, in this case 6.18 lb/hr, has been imposed as a BACT limitation. This limitation is derived from an emission factor for a well operated evaporator. The 5th step of the BACT process is satisfied as other control strategies were not found to be available or effective.

The commenter has also suggested this limit is counterproductive and inconsistent as it is a small source. UDAQ disagrees with this comment as well; a 6.18 lb/hr source results in the potential annual emissions of over 40 tons, and would not be considered an insignificant source of emissions.

No changes were made to the TSD or Part H limits as a result of this comment.

H-28[submitted by Compass Minerals]: Comments Specific to the PM2.5 Serious SIP Evaluation Report: Compass Minerals – Compass Minerals Ogden Inc.

Compass Minerals would like to clarify information for the record regarding the BACT evaluation in the PM2.5 Serious SIP Evaluation Report for Compass Minerals for the following sources:

Response to H-28: General Comments 1 thru 3:

Comment 1: 15.3.3 Step 3 Demonstration of Feasibility **-** Table 15-2 Feasibility Determination on page 26 of the Evaluation Report

For Boilers #1 and #2 VOC control: Table 15-2 and the narrative under the table are not consistent and the table should be amended to correctly reflect the analysis. As the narrative explains, the installation of oxidation catalysts was determined to be "infeasible" for boilers of this size and emission rate. The price per ton, $200,000/ton of VOC removed was well outside of standard BACT economic feasibility. It was concluded that the BACT evaluation should also serve as MSM. However, the Table 15-2 incorrectly has "Yes" in the column for whether the method is feasible. This mistake should be noted for the record.

Response to Comment 1: UDAQ recognizes the mistake made in Table 15-2, and agrees that these costs are not economically feasible and are well outside the range of standard BACT. This response serves as a correction to the TSD until time permits to update the TSD.

<u>**Comment 2:** IX.H.12.e.ii on page 27 of the Evaluation Report</u>

For sources with a filterable plus CPM limit, these sources exhibit exhaust moisture concentrations that prevent the use of EPA Method 201A, which allows for particulate size partitioning to quantify PM10 and PM2.5 emissions separately. In such cases, EPA Method 5 must be utilized for filterable PM measurement and size partitioning can either be achieved using AP-42 size fraction references or another measurement method approved by the Administrator.

Additionally, the recent addition of CPM to the definition of PM2.5 has not allowed Compass Minerals adequate opportunity to gather CPM emission data for all sources of this type. And, for the same reason, reliable CPM emission factors are often not available from reference sources. During stack testing, it is not technically possible to prevent a portion of filterable PM emissions collected from the stack from interacting with exhaust moisture to create artifact CPM in the sampling train. As a result, the total filterable PM and CPM collected during testing will often remain consistent, but their proportions may vary.

For these reasons, Compass Minerals requests a total PM2.5 limit which is the sum of post-stack-test-fractioned filterable PM measured using EPA Method 5 and CPM measured using EPA Method 202.

Response to Comment 2: UDAQ recognizes the difficulty in separating these emission limits into filterable and condensable; as such limits were listed as filterable plus condensable. See Table 1, in response to comment H-65 for the updated Part H limits.

Comment 3: IX.H.12.e.iii on page 27 of the Evaluation Report

Sources for which a filter PM2.5-only limit was requested by Compass Minerals include those sources from which only filterable PM emissions are anticipated, and exhaust moisture is low enough to allow the use of EPA Method 201A. Using this method, Compass Minerals can reliably partition filterable PM stack test samples to measure compliance with a filterable PM2.5- only limit.

Response to Comment 3: UDAQ recognizes that condensable PM2.5 limits are not applicable or expected at some sources, mainly sources that are pulling ambient air into the point source. However, given Compass Minerals condensable PM2.5 emissions report to date, and the lack of understanding as to where they are coming from, UDAQ has made the limits to include both filterable and condensable PM2.5 emissions. Where EPA Method 201A can be performed, so can EPA Method 202 to acquire both filterable and condensable measurements; in cases where water droplets are present, EPA Method 5 coupled with EPA Method 202 can be performed to achieve the same. No changes were made to the TSD or Part H limits as a result of this comment.

<u>Comments Submitted by Kennecott Utah Copper</u>

H-29[submitted by Kennecott Utah Copper]: UDAQ Misconstrued EPA's Explanation of BACT as Precluding Seasonally-Based Controls for Utah Power Plant (UPP) Unit #4 *(see UPP Comment No. 1)*

The only explanation offered by UDAQ for its shift away from a seasonal control strategy approach is premised on an isolated statement in the PM2.5 Implementation Rule preamble that BACT "is generally independent of attainment." UDAQ has indicated to KUC that it believes that EPA's "generally independent" statement requires BACT for coal firing outside of the wintertime inversion season. This rationale has been both articulated to KUC in conversations with UDAQ and alluded to in UDAQ's memorandum to the Board, which contains the following statement: "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."[8]

UDAQ has misconstrued EPA's discussion regarding the relationship of the attainment demonstration to BACM/BACT as precluding the common-sense, seasonal-control strategy that it has taken for almost 30 years. In fact, nothing in the PM2.5 Implementation Rule or its preamble precludes seasonal controls. To the contrary, designing a control strategy, including BACT controls, around the seasonal nature of the air quality circumstances that the SLC NAA area faces, is consistent with the CAA and its implementing regulations. Furthermore, addressing the seasonal nature of the problem is required pursuant to the Utah Air Conservation Act.

In the preamble, EPA explains the differences between the control requirements applicable in a Moderate nonattainment area (RACT/RACM) compared to those required for a Serious nonattainment area (BACT/BACM). In explaining the former, EPA states that, "the specific determination of RACM and RACT is to be made within the broader context of assessing control measures for all stationary, area and mobile sources of direct PM2. 5 and PM2.5 precursors that would collectively contribute to meeting the Moderate area attainment date as expeditiously as practicable.[9] "Measures that are not necessary for attainment need not be considered as RACM/RACT. [10] Clearly then, in assessing RACM/RACT, consideration may be given to the air quality benefits that would result from control measures being evaluated.

Turning to controls for Serious NAAs, the agency states that, "EPA has decided to maintain the policy that BACM/BACT determinations are to be 'generally independent' of attainment for purposes of implementing the PM2.5 NAAQS."[11] EPA explained that, "while RACM emphasizes the attainment needs of the area, BACM has a greater emphasis on identifying measures that are feasible to implement. Keeping in mind that the overall objective of the implementation of BACM and BACT and additional feasible measures is to bring a Serious PM2.5 nonattainment area into attainment as expeditiously as practicable, . . . the test for BACM puts a greater emphasis on the merits of the measure or technology alone, rather than on flexibility in considering other factors, in contrast to the approach for determining RACM and RACT."[12]

This qualified "general independence"13 is simply a recognition that compared to a RACT determination, there will be a "greater emphasis" on whether a particular control measure is technically and economically feasible compared to whether it is necessary for attainment. Nowhere in its discussion, however, does EPA suggest that there is an absolute prohibition on considering the relevance of the controls toward bringing an area into attainment; after all, that's the ultimate objective of the SIP planning process.

In the proposed rulemaking, EPA outlined an option for states to identify de minimis categories of sources that could be exempted from BACM/BACT. In the final rule, EPA declined to adopt such an option but noted that even without the exemption, "the final rule will nevertheless provide sufficient flexibility in the Serious area control measure analysis and attainment demonstration process, due to the availability of provisions enabling states to identify sources that should not be subject to control measures, including the ability to develop precursor demonstrations to exclude certain precursors from control requirements, and to consider case-specific factors in determining technical and economic feasibility of potential control measures."

So the statement that BACT "is generally independent of attainment" does not mean that no consideration be given to whether a control is appropriate or, more to the point, whether· account may be given to seasonal prohibitions. The recognition that states have "flexibility" and can consider "case-specific factors" when making the BACT determinations is far from a prohibition on seasonal controls. The acknowledgment that states may conduct precursor demonstrations is perhaps the most obvious recognition that BACT is not an absolute requirement.

While it is correct that, under EPA's interpretation of "general independence," UDAQ's determination of BACT for Unit #4 during the wintertime inversion season should place "greater emphasis" on whether a particular control measure is technically and economically feasible than on the resultant contribution to the attainment demonstration, there is no basis for looking to impose BACT level controls for an operating mode that is wholly prohibited during that period of time. This concept of general independence has no relevance to seasonal control measures.

H-30[submitted by Kennecott Utah Copper]: The CAA and Implementing Regulations Do Not Prohibit Seasonal Controls as Part of BACT *(see UPP Comment No. 2)*

As discussed in the preceding section of these comment, EPA's interpretation of "general independence" has no bearing on the appropriateness of seasonal control measures as part of a BACT determination. The CAA and its implementing regulations do, however, specifically address what constitutes an impermissible intermittent control; the use of seasonal controls is not precluded by these provisions.

Section 123 of the CAA includes a prohibition on "any intermittent or supplemental control of air pollutants varying with atmospheric conditions." EPA explains that intermittent control systems "vary a source's rate of emissions to take advantage of meteorologic conditions. When conditions favor rapid dispersion, the source emits pollutants at higher rates, and when conditions are adverse, emission rates are reduced."[18] In other words, prohibited intermittent controls are those that are engaged in response to specific atmospheric conditions.

Seasonal controls do not run afoul of section 123's prohibition (or that of EPA's implementing regulations codified in 40 CFR Part 51, subpart F) on intermittent controls systems: "Seasonal controls that are implemented at pre-determined periods of the year and that do not vary with atmospheric or meteorological conditions are not limited by section 123, even if they apply to stationary sources."[19] We assume UDAQ agrees since it has included such seasonal controls in past SIPs. [20] Importantly, the section 123 prohibition - and the exception from this prohibition for seasonal controls- applies broadly to any control measure (RACT or BACT) established under a State implementation plan.[21]

UDAQ's longstanding prohibition on coal combustion at UPP between November 1 and the end of February is not based on varying atmospheric conditions. Regardless of the air quality concentrations, meteorology, or the presence or absence of any other condition, the condition historically imposed by

UDAQ prohibits KUC from combusting coal during a specific four- month period. This is not an intermittent control prohibited by section 123 or EPA's implementing regulations.

H-31[submitted by Kennecott Utah Copper]: UDAQ's Entire Attainment Demonstration is Predicated on a Seasonal Approach *(see UPP Comment No. 3)*

UDAQ's decision to not recognize seasonal controls is at odds with its attainment demonstration. While UDAQ has not formally proposed its attainment demonstration, UDAQ has made clear that that demonstration will be based on a PM2.5 episode that occurred during the cold air pool event of January 1-10, 2011 and included multiple exceedance days.22 This makes sense in view of the broad recognition that the PM2.5 nonattainment problem is aligned with the wintertime inversion season.23 UDAQ's decision to ignore seasonality in the context of developing a control strategy for the UPP stands in stark contrast to its attainment demonstration focused on the wintertime inversion season.

The PM2.5 Implementation Rule supports a seasonal attainment strategy. For instance, the PM2.5 Implementation Rule allows states to develop emission inventories based on seasonal emissions as opposed to annual emissions.24 EPA explains the rationale for allowing seasonal inventories thusly,

> In the case of the 24-hour NAAQS ... the form of the NAAQS is based upon monitored values on particular days with high levels of ambient PM2.5 and in some nonattainment areas those days may occur only during a distinct and definable season of the year. The EPA considers it appropriate to interpret the emissions inventory requirements of the CAA in light of the specific inventory needs that are relevant for the NAAQS in question. * * *
>
> [T]he 24-hour PM2.5 NAAQS are designed to protect against peak exposures. Thus, for the 24-hour PM2.5 NAAQS, there are circumstances in which the EPA believes that only seasonal emissions inventories may be useful for attainment planning purposes. This rule at 40 CPR 51.1008(a)(l)(iii) allows states to use seasonal inventories for attainment plan development for attaining the 24-hour PM2.5 standard in areas that are designated nonattainment for only the 24-hour standard. Use of a seasonal emissions inventory will also be appropriate only if the monitored violations of the 24-hour PM2.5 NAAQS in the area occur during an identifiable season.[25]

Given that the SLC NAA's PM2.5 exceedances are limited to a specific season and UDAQ's recognition of this fact in preparing an attainment demonstration and emissions inventory based on the seasonal nature of the area's PM2.5 problem, UDAQ's determination that it will impose controls and emission limitations for operations that only occur outside of that defined season is unreasonable and arbitrary. The arbitrariness of UDAQ's determination is further illuminated by the fact that UDAQ's determination is in conflict with the agency's longstanding policy and interpretation that UPP's operations will be subject to a seasonally- based evaluation of controls.

As a result, KUC requests that UDAQ delete the language proposed in Part H.12.k.i.B, [26] which would impose emission limitations for Unit #4's coal combustion between March 1 and October 31. UDAQ should also retain the language, "During the period from November 1 to February 28/29, when burning natural gas ..."in Part H.12.k.i.A.[27]

H-32[submitted by Kennecott Utah Copper]: There is no Legal Basis for Imposing Controls on a Mode of Operation that Will Not Occur During the Wintertime Inversion Season *(see UPP Comment No. 4)*

As discussed above, seasonal controls are not prohibited under the CAA. Furthermore, in the case of UPP Unit #4, imposing controls on a mode of operation – coal firing – that is simply prohibited during the wintertime inversion season under the PM_{10} SIP, will have absolutely no relevance to the attainment strategy. Accordingly, there is no legal basis for imposing such controls.

In exercising its rulemaking authority, "[t]he board may establish emission control requirements by rule that *in its judgment may be necessary* to prevent, abate, or control air pollution that may be statewide or may vary from area to area, *taking into account varying local conditions."*[28] The rulemaking record does not satisfy this requirement for two reasons. First, there has been no finding of "necessity." To the contrary, as these comments make clear, not only are controls on coal-firing not necessary, they have no bearing whatsoever on the attainment strategy.

Second, there has been no determination that the controls for UPP Unit #4 'tak[e] into account varying local conditions," namely, the seasonal inversion conditions. Taking into account the fact that the SLC NAA's nonattainment problem is confined to the wintertime inversion season leads to the conclusion that controls on a mode of operation that is prohibited during the season are not necessary.

Given that the revisions UDAQ proposed for Part H.l2.k.i.B relate to Unit #4 combusting coal during the non-wintertime inversion season, KUC requests that UDAQ reject those proposed changes to the SIP and retain the SIP conditions as they currently exist.

H-33[submitted by Kennecott Utah Copper]: UDAQ's Proposed BACT Determination is Applied Arbitrarily as UDAQ Eliminated Seasonal Control for Unit #4 but Continued to Regulate Other SIP Sources via Seasonal Controls *(see Comment No. 5)*

Further undermining UDAQ's position that Unit #4's coal operations would be subject to BACT because UDAQ would no longer rely on seasonal controls is·the fact that UDAQ has allowed other sources to continue to be regulated in this manner in the PM2.5 SIP. For instance, UDAQ regulates Unit #3 of PacifiCorp's Gadsby Power Plant with the following provision,

111. Steam Generating Unit #3

A. Emission of NOx shall be no greater than

I. 142 lb/hr on a three (3) hour block average basis, applicable between November 1 and February 28129

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

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 a 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....29

Likewise, UDAQ regulates ATK Launch Systems with the following Condition

1. *During the period November 1 to February 28129* on days when the 24-hour average PM2.5 levels exceed 35 µg/m3 at the nearest real-time monitoring station, the open burning of reactive wastes with

properties identified in 40 CFR 261.23(a) (6) (7) (8) 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.

11. *During the period November 1 to February 28129,* on days when the 24-hour average PM2.5 levels exceed 35 µg/m3 at the nearest real-time monitoring station, the following shall not be tested:

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

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

I. A single test of rocket motors less than 1,000,000 lbs. of propellant per motor is allowed on a day when the 24-hour average PM2.5 level exceeds 35 µg/m3 at the nearest real- time monitoring station provided notice is given to the Director of the Utah Air Quality Division. No additional test of rocket motors less than 1,000,000 lbs. of propellant may be conducted during the inversion period until the 24- hour average PM2.5 level has returned to a concentration below 35 µg/m3 at the nearest real-time monitoring station.[30]

These provisions impose seasonal controls in a similar way to how UDAQ has previously regulated Unit #4. UDAQ imposed specific limitations and requirements that apply during a specific period of time (which is derived from the basis for the SLC NAA's PM2.5 nonattainment status). Like the Unit #4 prohibition on coal combustion, UDAQ imposed these provisions in an earlier version of the PM2.5 SIP. Yet, despite UDAQ's statements to KUC that UDAQ would no longer accept seasonal controls for the SLC NAA, UDAQ has, in fact, extended similar seasonal controls to other sources located in the SLC NAA.

It is a fundamental tenant of administrative law that it is arbitrary and capricious for an agency to apply one interpretation of the law to one party while applying a different, and contradictory, interpretation to another party. That is precisely what UDAQ has proposed to do here: UDAQ has proposed that ATK and PacifiCorp continue to be regulated through seasonal controls while eliminating similar seasonal controls for Unit #4.

H-34[submitted by Kennecott Utah Copper]: Given that neither the CAA nor the Act's implementing regulations preclude UDAQ from implementing seasonal control strategies in the $PM_{2.5}$ SIP, UDAQ ought to limit its review of BACT to potential controls for operations that occur during the SLC NAA's inversion season. As such, KUC requests that UDAQ remove the revisions to Parts H.12.k.i.B & C that UDAQ proposed in the current rulemaking. Moreover, such a withdrawal of the proposed BACT determination is required because UDAQ has not shown – and cannot show – how regulation of Unit #4's operations outside of the period of November 1 through the end of February is "necessary" for attainment and UDAQ has not taken into account varying local conditions impacting $PM_{2.5}$ concentrations, as required by the Utah Air Conservation Act. As UDAQ has done with other sources located in the SLC NAA, UDAQ should continue to apply its longstanding policy that the agency may evaluate controls on a seasonal basis for the $PM_{2.5}$ NAAQS; UDAQ cannot treat Unit #4's emissions differently than these other sources.

Comprehensive Responses to H-29 - H-34:

I. UDAQ Misconstrued EPA's Explanation of BACT as Precluding Seasonally-Based Controls for UPP Unit #4

The commenter is correct that the description of BACM / BACT as "generally independent" of the attainment demonstration does not mean that it is entirely independent. However, DAQ never intended that such general independence would necessarily exclude the option of including seasonal controls and agrees with the commenter that EPA does not suggest that it would.

II. The CAA and Implementing Regulations Do Not Prohibit Seasonal Controls as Part of BACT.

DAQ understands the distinction between the intermittent controls that vary with atmospheric conditions and seasonal controls that are enacted during a pre-defined portion of the year. For purposes of this seasonal controls discussion, the winter PM season along the Wasatch Front has been defined as beginning on November 1 and extending through the last day of February. UDAQ will retain the common-sense, seasonal-control strategy that it has taken for almost 30 years by retaining the prohibition on coal as a fuel during the wintertime inversion season. Coal burning will be allowed during the periods outside of the winter PM season. However, UDAQ will continue to require that Unit 4 comply with BACT limitations during all periods of operation. As stated in the following response (Response to H-29-34.III), BACT was evaluated on an annual basis and limitations were established as such.

As indicated in the comments, such seasonal controls have been made part of prior SIPs for particulate matter. Yet, most of these sources are no longer regulated in a seasonal sense. In fact, the only sources that have seasonal-based limits are Gatsby Power Plant, ATK, and Kennecott's UPP Unit #4 now that UDAQ has agreed to retain the prohibition on coal burning during the wintertime inversion. Kennecott's UPP is the only remaining source to retain an operating mode that accommodates summertime coal-burning. Furthermore, although Gatsby Power Plant and ATK have Part H limitations that include seasonal conditions, these sources still have limits that apply year-round and are considered BACT (as discussed in Response to H-29-34.V).

III. UDAQ's Entire Attainment Demonstration is Predicated on a Seasonal Approach.

The commenter is correct that DAQ is basing its modeling analysis upon the meteorology incurred during an episode transpiring basically from January 1-10, 2011. This establishes meteorological conditions known to enhance formation of secondary $PM_{2.5}$ and to contain all $PM_{2.5}$. The commenter is also correct that DAQ has compiled the various components of the emissions inventory into what is presented as representing an average-episode-day. These emissions reflect, in many cases, a seasonal adjustment to more accurately represent emissions typically seen during winter months. Unit #4 was represented in this inventory as burning natural gas.

Nonetheless, the modeled analysis does consider ambient levels of $PM_{2.5}$ collected throughout the entire year. This data is included in the ranking of all data so as to identify a 98th percentile value for each year at each monitor. Additionally, the data evaluated in the Speciated Modeled Attainment Test (SMAT), the software used to model attainment tests for daily $PM_{2.5}$, includes days collected outside of the winter PM season. SMAT applies the Relative Reduction Factors from CAMx to the speciation of select filters to project future concentrations for the entire year. Therefore, although the modeling analysis is based on meteorological conditions that occurred in January 2011 and seasonal-adjusted emissions, the attainment demonstration at each monitor included year-round data. Therefore, the commenter's claim that the entire attainment demonstration is predicted on a seasonal approach is inaccurate.

Furthermore, the BACM /BACT provisions include numerous examples of emission controls that apply outside of the winter PM season. Such examples include:

- R307-309 – Non-attainment and Maintenance Areas for PM_{10} and $PM_{2.5}$: Fugitive Emissions and Fugitive Dust
- R307-312 – Aggregate Processing Operations for $PM_{2.5}$ Nonattainment Areas
- R307-342 through R307-361 – Process-specific area source rules applicable to coatings, graphic arts, aerospace manufacture and rework facilities, and other operations that have the potential to emit direct $PM_{2.5}$ and precursors.

Similarly, UDAQ evaluated BACT on an annual basis for all major sources in the nonattainment area. Per the implementation rule, UDAQ is required to develop a control plan as part of the serious SIP. The control plan includes BACT limits for all major sources of $PM_{2.5}$ and $PM_{2.5}$ precursors in the nonattainment area. The primary purpose of UDAQ's analyses was to ensure that all major sources within the $PM_{2.5}$ nonattainment area are subject to BACT requirements. BACT reviews were not intended to evaluate whether a control is necessary to meet attainment. As part of the BACT analysis for Unit #4, UDAQ evaluated the technical and economic feasibility of various NO_x controls for three operating scenarios for Unit #4: 1) natural gas burning year-round; 2) natural gas burning between November 1 and February 28/29; and 3) coal burning between March 1 and October 31. BACT determinations were based on the technical and economic feasibility of installing controls for each of these operating scenarios. The BACT analysis for the combustion of natural gas concluded that an OFA/LNB system with SCR is a technically and economically feasible option for both year-round and seasonal operations. The BACT analysis for coal usage during the period of March 1 and October 31 also concluded that OFA/LNB system with SCR is economically and technically feasible. Therefore, the NO_x emission limits for Unit #4 will reflect the control of NO_x using SCR for both natural gas and coal operations.

As stated in this response, UDAQ has established BACM/BACT for both area sources and major sources on an annual basis and has consistently required controls that apply outside the winter PM season. UDAQ disagrees with commenter statement that *"UDAQ's determination that it will impose controls and emission limitations for operations that only occur outside of that defined season is unreasonable and arbitrary"*. UDAQ believes that a BACT determination to limit emissions from Unit 4 on a continuous basis is, in fact, more consistent with other determinations of BACT/BACM in this SIP.

In response to Comment H-58.E, UDAQ has also conducted a preliminary BACT review for SO_2 controls for Unit #4. The proposed Part H limitations for SO_2 are included in the Conclusions section of this response. Please refer to the response to Comment H-57.E for more details.

IV. There is no Legal Basis for Imposing Controls on a Mode of Operation that Will Not Occur During the Wintertime Inversion Season

Based on the responses provided and revisions to the SIP conditions applicable to Unit #4, the proposed controls are legally and technically justified. UDAQ agrees with the commenter that seasonal controls are not prohibited under the CAA and retains the seasonal prohibition on coal-burning at Unit #4. Imposition of additional controls year-round as BACT is linked to the attainment strategy and is not irrelevant as the commenter suggests. As explained in detail in response under III above, the modeled analysis UDAQ presents as part of its attainment strategy considers data collected year-round (including summer season when Unit #4 can burn coal) to identify the annual 98th percentile value for each monitor. Data for days outside of the winter season was also evaluated in SMAT software to project future annual concentrations of particulate matter. Consequently, limitations on emissions imposed through the BACT analysis (OFA/LNB with SCR) are technically and legally appropriate.

UDAQ's proposed conditions on Unit #4 (seasonality requirement and BACT) comply with the Utah Air Conservation Act that the commenter cites as they are "necessary to . . . control air pollution . . . taking into account varying local conditions." Utah Code Ann. § 19-2-109(2)(a). As explained above, controls on coal-firing bear on the attainment strategy and are necessary. Local conditions are considered by retaining the seasonality requirement i.e., prohibition on burning coal at Unit #4 during the winter season. The Utah Air Quality Board rulemaking authority certainly includes the authority to adopt the proposed revisions to the SIP conditions that apply to Unit #4.

V. UDAQ's Proposed BACT Determination is Applied Arbitrarily as UDAQ Eliminated Seasonal Control for Unit #4 but Continued to Regulate Other SIP Sources via Seasonal Controls

The commenter stated that DAQ allowed seasonal controls to other sources located in the nonattainment area and removed the seasonal-based limits for Unit #4. Specifically, DAQ allowed Gatsby Power Plant and ATK Launch Systems to have seasonal controls. The commenter stated that "it is arbitrary and capricious for an agency to apply one interpretation of the law to one party while applying a different, and contradictory, interpretation to another party."

UDAQ disagrees that its action here is arbitrary, as it provides a reasoned explanation and basis for its decision. As stated in Response to H-29-34.II, UDAQ has proposed to retain the prohibition on coal as a fuel during the wintertime inversion season but has maintained BACT limitations that apply to all periods of operation, including those outside winter PM season. UDAQ would also like to note that although Gatsby and ATK have more stringent seasonal controls, these sources also have limits that apply year-round and are considered BACT.

The Gadsby Power Plant is required to meet a NOx emission rate in Steam Generating Unit #3 of 142 lb/hr on a three-hour block average between November 1 and February 28/29 and 203 lb/hr between March 1 and October 31. The BACT analysis for Gatsby Power Plant was based on the 2016 actual emissions for Units #1, #2, and #3 combined. Based on these actual emissions, the installation of additional controls was not economically feasible. These units operate at significantly reduced capacities and have much lower emissions than KUC's Unit#4 (102 tons of NOx for all three units combined compared to 650 tons of NOx for Unit #4). Because no additional control measures were identified during the BACT review for Units #1, #2, and #3, DAQ maintained the Title V permit limits for these units, which included the seasonal limitations. As part of the response to public comments, DAQ has added the concentration-based limit of 168 ppmvd to Part H. This limit was included in the Title V permit and AO and applies year round. The seasonal limits only apply to the lb/hr limit for Unit #3; the concentration-based limit does not change on a seasonal basis.

Similarly, ATK Launch systems has limits for open burning of propellant and rocket motor testing that only apply during the period of November 1 to February 28/29. BACT for this process was done based on 2016 actual emissions. No additional control technologies were identified as BACT. Therefore, DAQ did not change this Part H limit as part of this revision. The seasonal limitation at ATK is intended to eliminate certain activities during the wintertime and not to eliminate a BACT review on an annual basis. Another consideration specific to this source is that storage of reactive hazardous waste is a safety hazard. To lower the safety hazard but also minimize pollutants into the cool pool, a restriction is placed on open burning of waste. Also, ATK is required to have the ability to test one large rocket motor during the winter to be a viable operation for the United States government space program.

VI. Conclusion to KUC's UPP Comments

In summation, KUC has requested that UDAQ retain the SIP conditions as they currently exist. Specifically, that UDAQ:

- *remove the revisions to Parts H.12.k.i.B & C*
- *delete the language proposed in Part H.12.k.i.B, which would impose emission limitations for Unit #4's coal combustion between March 1 and October 31. UDAQ should also retain the language, "During the period from November 1 to February 28/29, when burning natural gas ..."in Part H.12.k.i.A.*
- *reject those proposed changes to [Part H.l2.k.i.B related to Unit #4 combusting coal during the non-wintertime inversion season] and retain the SIP conditions as they currently exist.*

In order to ensure consistency with other sources in the SIP, UDAQ will revise the Part H limit to allow for seasonal provisions. However, BACT will still be required on an annual basis so the limits related to coal combustions during the non-wintertime inversion season are maintained. The revisions to Parts H.12.k.i.B & C will be maintained, with some additional revisions proposed as shown below. UDAQ has retained the language, "During the period from November 1 to February 28/29, when burning natural gas ..." in Part H.12.k.i.A.I.

DAQ has revised the Part H limit as follows:

i. Utah 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:]~~

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

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. Unit #4 may then burn coal, only for the duration of the curtailment plus sufficient time to empty the coal bins following the curtailment.

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

Pollutant	grains/dscf 68oF. 29.92 in Hg	ppmdv 3% O_2	lbs/hr	lbs/MMBtu	lbs/event
[~~I~~]1. $PM_{2.5}$:					
Filterable		0.004			
Filterable + condensable		0.03			
[~~II~~]2. NO_x:		20	17.0	0.02	
Startup / Shutdown					395
~~[III.~~ ~~NH4~~			~~2.0*]~~		

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

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

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

* Except during startup and shutdown.

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

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

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

3. Definitions:

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

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

A. 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.II and IX.H.12.k.i.[~~B~~]A.IV 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. NH4~~	~~every year~~]

H-35[submitted by Kennecott Utah Copper]: The Emission Cap on KUC's Haul Trucks and Other Nonroad Engines is a Standard which the CAA Preempts UDAQ from Imposing on Nonroad Engines *(see Bingham Canyon Mine (BCM) Comment No. 1)*

Response to H-35: KUC's comments discuss at length that Title II of the Clean Air Act preempts any state regulation of mobile source emissions, either road or nonroad. To demonstrate how UDAQ is preempted from regulating these emissions, KUC presents at least two ways of how it could comply with the proposed emission cap: limiting production and either retrofitting or retiring haul trucks. UDAQ addresses both in turn.

<u>Limiting Production</u>

KUC characterizes the emissions caps proposed in Part H.12.j. of the SIP as "standards" that Title II forbids the state from imposing on the Bingham Canyon Mine haul trucks. However, KUC improperly characterizes this option as a production limitation – that the proposed SIP condition is actually a production limitation designed to force a reduction in the use of haul trucks, which will result in moving less material. If anything, this characterization is backward. Impact on production, if any, would be a possible consequence of limiting mileage on the haul trucks, not a hard limit on production that would force the limit on the truck usage.

Continuing to assume that the SIP conditions are actually a production limit, KUC claims that UDAQ has never imposed mandatory production curtailment as a SIP control strategy. KUC states (without citation) that a "SIP control strategy" that limits production (which, again, mischaracterizes the SIP conditions as they were proposed) is inconsistent with state "policy of fostering prudent economic development." This ignores the fact that a balancing must always occur between economic development and compliance with environmental protection laws.

However, KUC acknowledges that UDAQ may impose in-use rules on nonroad vehicles. *See* Kennecott Utah Copper Comments (KUC Comments) at 12 (Aug. 15, 2018). Accordingly, to avoid any conflict with Title II, UDAQ has revised the conditions in Part H.12.j. as follows:

> "The 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."

Limiting the mileage on the haul trucks controls only the use of the trucks but imposes no emission limit on the truck engines, and therefore is an in-use rule and not a standard that could potentially conflict with Title II. KUC suggests that a limit on truck miles is a limit on production, but cites no authority stating that a SIP condition cannot have any impact on a source's production goals. Again, all SIP conditions have an impact on the sources subject to them.

KUC also states that if UDAQ intends to impose production limitations on KUCC, that it "provide the legal basis for doing so." Because the SIP proposal on its face does not limit production, there is no "intention" to do so for which UDAQ need provide a legal basis, and KUC provides no authority to the contrary. In any event, the legal basis for imposing the in-use requirement consists of the following:

1. U.C.A. § 19-2-104 (Utah Air Quality Board's broad authority to make rules "regarding the control, abatement, and prevention of air pollution from all sources and the establishment of the maximum quantity of air pollutants that may be emitted by an air pollutant source.").

2. 42 U.S.C. § 7543(d): "Nothing in this part shall preclude or deny to any State or political subdivision thereof the right otherwise to control, regulate, or restrict the *use, operation, or movement* of registered or licensed motor vehicles." Limiting the daily mileage of the haul trucks is clearly a control, regulation, or restriction on the "use, operation, or movement" of the haul trucks. As KUC acknowledges, this section of the Clean Air Act applies to nonroad engines. *See* KUC Comments at 12, 12 n.36.

3. *Engine Mfrs. Assn. v. E.P.A.*, 88 F.3d 1075, 1093 (D.C. Cir. 1996) (stating that "Section 209(d) does . . . protect the power of states to adopt such in-use regulations."

4. 59 Fed. Reg. 36969, 36973 n.16. ("Congress clearly anticipated that all of section 209 would be applicable to nonroad engines.").

5. 81 Fed. Reg. 58010-01, 58084 n.166 (Preamble to $PM_{2.5}$ Implementation Rule stating that states should consider Transportation Control Measures).

Based on these authorities, UDAQ and the Utah Air Quality Board can impose a mileage limitation on the haul trucks as an in-use rule, or as explained later, as a Transportation Control Measure (TCM). KUC itself states that in-use rules and TCMs are not preempted under Title II and that "[a]n in-use regulation dictates how an owner operates a vehicle and the state is policing conduct in such regulations.") KUC Comments at 14. The proposed mileage limitation only regulates how KUC uses its trucks but does force KUC to retire or retrofit its trucks, or otherwise set a limit on truck emissions.

As to any impact in production, UDAQ does not agree that reinstating a mileage limitation is equivalent to a production limit. The limitation of 30,000 miles per day has been a limit in the SIP since at least 1996. This limit was preserved when the mine expansion was permitted in 2011. In fact, in 2011 KUC requested a voluntary emission limit of 6,205 tons of NO_x, $PM_{2.5}$, and SO_2 as part of the mine expansion modification but did not request to change the mileage limitation. UDAQ also evaluated BCM's actual production and mileage based on data submitted in the emissions inventory between 2012 and 2017 in an attempt to establish a relationship between mileage and production. During this time period, KUC operated approximately between 74% and 90% of the production limit of 260,000,000. During the same time period, KUC's annual mileage was estimated at approximately 39% to 52% of the equivalent annual limit of 10,950,000 miles, or 30,000 miles per calendar day multiplied by 365 days. For these reasons, UDAQ believes that KUC is more likely to reach its production limit before it reaches its mileage limit.

KUC states that the 2014-16 emissions inventory is not representative of its normal operations due to a slide in the pit in 2013. It is not clear how the slide impacted the operational data in the emission inventory data. Even if UDAQ were to exclude data from 2013 through 2016, operational data from 2012 and 2017 also indicates that mileage is not a main limiting factor on production.

Therefore, as revised the proposed SIP conditions limiting haul truck miles do not conflict with Title II, and are permissible.

Retrofitting or Retiring Haul Trucks

Because UDAQ is proposing to limit the haul truck mileage, KUC would not need to retrofit or retire trucks to comply with the SIP. KUC can retrofit or retire trucks if it wishes to do so, or as its business purposes necessitate. The condition proposed in Part H.12.j.i.E for haul truck replacement has been removed.

H-36[submitted by Kennecott Utah Copper]: *Even Assuming UDAQ can Regulate KUC's Haul Truck Fleet in the Method Proposed in Part H.l2.j.i.B,* UDAQ has not Followed the BACT Process

Response to H-36: KUC's comments on the haul trucks BACT analysis are based on the emissions caps originally proposed. As explained in previous responses, UDAQ now proposes a mileage limitation for the haul trucks as an in-use regulation or a TCM.

As previously stated, the mileage limitation of 30,000 miles per day was the original limit in Part H.12 and has been in SIPs since 1996. UDAQ will revise the limit in Part H.12.j.i.A proposed on July 1, 2018 and re-establish the mileage limitation included in previous SIPs. KUC is also subject to this mileage limitation in Part H.2 of the PM_{10} SIP.

H-37[submitted by Kennecott Utah Copper]: *Even Assuming UDAQ can Regulate KUC's Haul Truck Fleet in the Method Proposed in Parts H.12.j.i.A* & *H.12.j.i.B,* UDAQ's is Limited to Evaluating Transportation Control Measures for Mobile Source Emissions *(see BCM Comment No. 3)*

In the preamble to the $PM_{2.5}$ Implementation Rule, EPA directs states to determine BACM for mobile source emissions. Given the preemption that title II imposes on UDAQ, the question becomes what should UDAQ have evaluated as BACM for mobile sources in preparing the $PM_{2.5}$ SIP. The preamble to the $PM_{2.5}$ Implementation Rule provides direction on this very issue, as EPA states,

Specific to potential control measures for mobile source emissions, the EPA's past guidance has indicated that where mobile sources contribute significantly to $PM_{2.5}$ violations, "the state must, at a minimum, address the transportation control measures listed in CAA section 108(£) to determine whether such measures are achievable in the area considering energy, environmental and economic impacts and other costs.

In other words, the state should review potential transportation control measures when identifying potential controls for mobile sources as part of a BACT analysis. In making this statement, EPA understood that transportation control measures are not preempted by title II.

Given this guidance, UDAQ should have limited its review of potential control strategies for KUC's haul trucks and other nonroad engines to potential transportation control measures.

Response to H-37: UDAQ agrees that Transportation Control Measures (TCM) are not preempted by Title II. As explained in response to Comment H-35, UDAQ has revised the proposed SIP conditions to limit the mileage on the haul trucks instead of imposing an emissions cap. UDAQ considers this revised condition to be an in-use rule. Additionally, the haul truck mileage limitation also qualifies as a TCM.

42 U.S.C. § 7408(f)(1)(A) contains a nonexclusive list of various transportation control measures, and 40 C.F.R. § 51.51.100(n)(7) defines “control strategy” as including “transportation control measures.” 40 C.F.R. § 93.101 defines “transportation control measure” as “*any* measure that is specifically identified and committed to in the applicable implementation plan, including a substitute or additional TCM that is incorporated into the applicable SIP through the process established in CAA section 176(c)(8), that is either one of the types listed in CAA section 108, *or any other measure for the purpose of reducing emissions or concentrations of air pollutants from transportation sources by reducing vehicle use* or changing traffic flow or congestion conditions.”

Therefore, a TCM can be “any measure” that reduces emissions from transportation sources by reducing vehicle use. Limiting the mileage of the haul trucks will reduce emissions. As KUC notes, EPA does not understand TCMs to be preempted by Title II, *see* KUC Comments at 18, and KUC also acknowledges that UDAQ may use in-use rules, *id*. at 12, 12 n.36. Nothing in the 40 C.F.R. § 93.101 definition excludes nonroad vehicles such as haul trucks. Therefore, TCMs can be applied to nonroad vehicles such as KUC’s haul trucks.

Moreover, KUC suggests that a TCM should apply broadly and not just to the Bingham Canyon Mine. *See* KUC Comments at 18. However, none of the authorities cited here support a reading that a TCM cannot be used specifically for KUC. Indeed, the definition states that a TCM can be “*any other measure* for the purpose of reducing emissions or concentrations of air pollutants from transportation sources *by reducing vehicle use*.” 40 C.F.R. § 93.101. In this instance, the “transportation sources” are the haul trucks in use at the Bingham Canyon Mine. No language in this definition precludes its application in the form of the haul truck mileage limitation specific to KUC’s haul trucks, as now proposed.

H-38[submitted by Kennecott Utah Copper]: Even Assuming UDAQ can Regulate KUC's Haul Truck Fleet in the Method Proposed in Parts H.l2.j.i.A & H.l2.j.i.B, it is NOT Feasible to Upgrade the Existing Haul Trucks and New Higher-Tiered Trucks Meeting KUC's Mining Needs are not Available *(see BCM Comment No. 4)*

Response to H-38: UDAQ has removed the proposed emission cap proposed in Part H.12.j.i.A and instead recommends that the Board impose a mileage limitation on the haul trucks as an in-use rule or TCM. Therefore, KUC need not upgrade its haul trucks to comply with the SIP. The condition proposed in Part H.12.j.i.E for haul truck replacement has been removed.

H-39[submitted by Kennecott Utah Copper]: *Even Assuming UDAQ can Regulate KUC's Haul Truck Fleet in the Method Proposed in Part H.12.j.i.B,* UDAQ Arbitrarily Based the Emission Limitation on Minimal Variability *(see BCM Comment No. 5)*

Response to H-39: UDAQ has removed the proposed emission cap proposed in Part H.12.j.i.A and instead recommends that the Board impose a mileage limitation on the haul trucks as an in-use rule or TCM.

H-40[submitted by Kennecott Utah Copper]: For the foregoing reasons, UDAQ has overstepped its authority to regulate the BCM's fleet of nonroad engines in the proposed revisions to Part H of the $PM_{2.5}$ SIP. Title II of the CAA preempts UDAQ from imposing the emission limitations that UDAQ has proposed in the current rulemaking. Furthermore, even if UDAQ had the authority to regulate the nonroad engines in this manner, (i) its BACT determination did not follow the procedures for evaluating BACT, should have been limited to a review of potential transportation control measures, and failed to adequately determine if retrofits and replacements were either technologically or economically feasible, and (ii) UDAQ arbitrarily determined the emission limitations that it proposed for the BCM's haul truck fleet. KUC requests that UDAQ strike all provisions from Part H regulating the BCM's nonroad engines from the proposed revisions as well as the existing PM_{10} and $PM_{2.5}$ SIPs.

Response to H-40: This comment restates KUC's previous comments, to which UDAQ has already responded. Please see responses to Comments H-35-39.

H-41[submitted by Kennecott Utah Copper]: PM_{10} SIP Comment. UDAQ Should Revise the PM_{IO} SIP so that Parts H.2 and H.12 are Consistent

While the current rulemaking is intended to implement control strategies for point sources under the $PM_{2.5}$ SIP, UDAQ proposed a number of revisions to the PM_{IO} SIP as well. It appears that UDAQ opened up the PM_{IO} SIP as part of the current rulemaking to make the existing PMlO SIP consistent with the $PM_{2.5}$ SIP.

KUC supports UDAQ's attempt to make the PM_{IO} and $PM_{2.5}$ SIP consistent. Each of these SIPs is independently enforceable, meaning that sources subject to both SIPs are required to comply with the requirements of both. By normalizing the two documents, UDAQ eases the burden on both regulators and the source to determine compliance. Additionally, establishing consistency between the SIPs streamlines the title V permitting process.

Kennecott therefore requests that UDAQ revise the conditions applicable to KUC in Part H.2 of the PM_{10} SIP to be consistent with the proposed revisions to the conditions applicable to KUC in Part H.12 of the $PM_{2.5}$ SIP.

Response to H-41: Where appropriate, UDAQ has revised portions of the Part H.2 of the PM_{10} SIP to be consistent with the proposed revisions in Part H.12 of the $PM_{2.5}$ SIP. The proposed changes to Part H.2 of the PM_{10} SIP are shown in the revised Part H document included as part of this package.

H-42: (submitted by Kennecott Utah Copper]: Bingham Canyon Mine and Copperton Concentrator *(see TOPIC 4: Specific Comments on Other Part H.12 Conditions and SIP Evaluation Reports)*:

<u>Comment 1:</u>
A review of the BACT analysis for the in-pit crusher at the Bingham Canyon Mine is presented in DAQ-2018-007709. Emissions from the crusher are currently controlled with a high efficiency baghouse. Based on manufacturer information, the baghouse is designed to achieve a control efficiency of99.9 percent. This removal efficiency is consistent with the BACT rate (correctly) established by UDAQ for baghouses in DAQ-2018-007161, Appendix A: BACT for Various Emissions Units at Stationary Sources. The in-pit crusher at the BCM is within the scope of emissions units addressed by DAQ-2018-007161.

Furthermore, while KUC does not agree with the need for a separate BACT review for the in-pit crusher, KUC submitted iterations of detailed BACT analyses for the in-pit crusher in 2017 and

2018 and incorporates those submissions by this reference. The BACT emission rate included in DAQ-2018-007709 for the in-pit crusher is arbitrary and should be based on the BACT analysis. BACT for the in-pit crusher is a high efficiency baghouse with a control efficiency of 99.9 percent.

Section 2.1.1, Section 3.0, and Subparagraph D in Section 6.0 of DAQ-2018-007709 should be deleted as the BACT review for baghouses in DAQ-2018-007161 Section 3 is applicable. Section 5.0 of DAQ-2018-007709 should also be modified to indicate proper operations are already in place. Please see the SIP Evaluation Report markups provided in Appendix 1 of these comments.

Additionally, KUC is requesting a modification to the Part H limitation for the in-pit crusher. Condition j.i.D in Part H.12 should be deleted.

Response to H-42:

Comment 1 Response:

The commenter stated that "the in-pit crusher at the BCM is within the scope of emissions units addressed by DAQ-2018-007161" and that the BACT review for the in-pit crusher should be removed from the KUC BCM TSD document. DAQ-2018-007709, Appendix A to Part H, includes a BACT analysis for baghouse dust collectors. Appendix A was created to more efficiently and consistently address BACT for small emission sources found in several major sources. UDAQ consolidated the review of these smaller units into one document and included this document as Appendix A to Part H. As UDAQ staff prepared TSDs for individual sources, staff could refer to the information in Appendix A in the discussion of BACT for small emission units. This not only ensured consistency between sources but also allowed more time for staff to focus on the larger emission units. However, these analyses were not intended to replace a discussion of small emission units in TSD documents. UDAQ's objective was to include discussions of the small emission units at each source in their respective TSDs and make BACT determinations as recommended in Appendix A or based site-specific information.

The analyses in Appendix A were useful in documenting available technologies, technical and economic feasibility, ranking of technologies (e.g. Steps 1 through 4 of a top-down BACT analysis), but many of these analyses were not able to make final BACT determinations (Step 5 of a top-down BACT analysis). For these analyses, selection of control technology has to be determined on a case-by-case basis in order to account for process-specific variabilities, such as materials processed, fuels, operating parameters (pressure, temperatures, pH of gas stream), operational hours, etc.

For the baghouse evaluation in Appendix A, different control efficiencies were evaluated (99% vs 99.9%). The analysis found that the more efficient is often technically feasible, but that there may be some instances where a more efficient baghouse is not technically or economically feasible. The analysis concluded that "[e]ach site must evaluate the feasibility based on operation type and design." Therefore, UDAQ conducted an analysis specific to BCM's in-pit crusher baghouse as part of the TSD.

KUC also stated that the BACT for the in-pit crusher should be a baghouse with 99.9% control efficiency. UDAQ evaluated BACT in terms of concentration-based and emission rate limitations rather than control efficiencies because the in-pit crusher baghouse has a concentration-based emission limitation and stack testing requirements in Condition II.B.1.a of AO DAQE-AN105710042-18. Furthermore, concentration-based and emission rate limitations are consistent with the definition of BACT in 40 CFR 52.21(b)(12) and in UAC R307-401-2 of *"an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation ..."*.

The $PM_{2.5}$ implementation rule requires that existing sources of all $PM_{2.5}$ precursors in the area are subject to evaluation for BACM/BACT control measures, i.e. the more stringent regulatory requirement. The in-house crusher baghouse is currently limited to an emission rate of 0.016 gr/dscf (1.77 lb/hr) in AO DAQE-AN105710042-18. UDAQ identified other baghouses with more stringent emission rate limitations (0.002 gr/dscf to 0.003 gr/dscf) during a review of the EPA's RBLC Clearinghouse database. Stack testing results from this baghouse also indicated that the baghouse operates at lower emission rates than permitted. The highest $PM_{2.5}$ emission rate measured during the stack tests conducted between 2000 and 2015 is 0.001 gr/dscf (0.164 lb/hr). Given this operational data and BACT determinations in other operations, UDAQ determined that the BACT limit could be revised to meet the more stringent emission limits.

KUC initially proposed a limit of 0.30 lb/hr. However, the manufacturer was not able to guarantee this emission rate due to the significant variation in the ore and the air borne coarse dust in the surrounding area. After further evaluation of the initial proposal, KUC proposed a new limit of 0.78 lb/hr. UDAQ included this proposed limit in Part H.

KUC stated that *"emission rate included in DAQ-2018-007709 for the in-pit crusher is arbitrary"* UDAQ disagrees with this statement. The emission rate in Part H is an appropriate BACT limit and is based on operational data and was proposed by KUC. UDAQ relied on KUC to propose a limit that is appropriate for their operations after consulting with the baghouse manufacturer. An emission rate for the in-pit crusher baghouse is also consistent with the types of limits for other baghouses in the EPA's RBLC Clearinghouse and with the type of limit in the AO DAQE-AN105710042-18.

No changes will be made to the Part H limit or the BACT discussion of the in-pit crusher as a result of this comment.

<u>Comment 2:</u>
A review of the BACT analysis for haul roads at the BCM is presented in DAQ-2018-007709. Fugitive emissions from haul roads are currently controlled by application of water, dust suppressant and road base material. These controls are consistent with the BACT evaluation in DAQ-2018-007161, Appendix A: BACT for Various Emissions Units at Stationary Sources.

Section 2.1.5 of DAQ-2018-007709 should be deleted as the BACT review for haul roads in DAQ-2018-007161 Section 12G is applicable. Please see the SIP Evaluation Report markups provided in Appendix 1 of these comments.

Comment 2 Response:

The commenter stated that haul roads "are consistent with the BACT evaluation in DAQ-2018-007161, Appendix A" and that haul road BACT review should be removed from the KUC's BCM TSD document. DAQ-2018-007709, Appendix A to Part H, includes a BACT analysis for haul roads in Section 12.G.

As previously stated, Appendix A was created to more efficiently and consistently address BACT for small emission sources found in several major sources. However, these analyses were not intended to replace a discussion of small emission units in TSDs documents. UDAQ's objective was to include discussions of the small emission units in each TSD and make BACT determinations as recommended in Appendix A or based site-specific information.

The analysis in Appendix A for haul roads mentions KUC when discussing limitations of chemical suppressant and paving. This was simply meant to provide specific evidence on instances when these controls are not feasible options for controlling haul road emissions. In general, the analysis Appendix A was were useful in documenting available technologies, technical and economic feasibility, ranking of technologies (e.g. Steps 1 through 4 of a top-down BACT analysis), but many of these analyses were not able to make final BACT determinations (Step 5 of a top-down BACT analysis). This analysis is not intended to replace a BACT analysis specific to Kennecott.

No changes were made in response to this comment.

Comment 3:
Pages 11 and 12 ofDAQE-2018-007709 provides a BACT review for the ore and waste haul trucks and other nonroad support equipment operated at the BCM. Condition j.i.A and Condition j.iB in Part H.12 includes emissions limitations for nonroad engines at the Bingham Canyon Mine.

UDAQ has stated that the modifications to Part H limits are considered BACT determinations. BACT is an evaluation of technically and economically feasible potential emission controls. Even if a BACT evaluation were appropriate for engines regulated by Title II, no technically and economically feasible add-on emission control technologies have been identified for nonroad engines.

For the reasons explained in Topic 2 of KUC's comment letter, all discussion regarding emissions from haul trucks should be eliminated from the SIP Evaluation Report. However, even assuming that UDAQ can regulate KUC's haul truck fleet in the method proposed in Part H.12, UDAQ has not followed the BACT process.

Section 2.1.5, Section 3.0, references to nonroad engines in Section 5.0 and Subparagraphs A, B and E in Section 6.0 of DAQ-2018-007709 should all be deleted. Conditions j.i.A, j.i.B, j.i.D and j.i.E of Part H.12 should also be deleted. Please see the SIP Evaluation Report markups provided in Appendix 1 of these comments and further review of this issue in Topic 2 of KUC comments.

Comment 3 Response:

UDAQ has removed the emission limitation for nonroad engines at the Bingham Canyon Mine. See Response to H-35 through H-40.

Comment 4:
A review of the BACT analysis for the Tioga heaters at the Copperton Concentrator is presented in DAQ-2018-007709. The heaters are rated at less than 5 MMBTU/hr each. Specifically, the facility includes seven (7) 4.2 MMBtu/hr natural gas fired heaters and one (1) 2.4 MMBtu/hr natural gas fired heater.

KUC submitted iterations of detailed BACT analyses for the Tioga heaters in 2017 and 2018. The iterations reflect the variations in emissions reported in the Annual Emissions Inventories. Emissions for these heaters are calculated based on their natural gas consumption. KUC continuously refines its calculation methodology to accurately estimate emissions from the heaters. The 2017 actual emissions for the Tioga heaters are 0.63 tons per year of NO_x. In previous years, KUC has employed a conservative method to attribute natural gas consumption to the heaters which has resulted in a conservative estimate of emissions. In 2017, however, KUC updated the estimation methodology (instead of using the conservative estimated consumption rates that KUC used previously).

As established in DAQ-2018-007161, Appendix A: BACT for Various Emissions Units at Stationary Sources, KUC already implements the BACT requirements for the heaters. Section

2.2.1, Section 3.0, and Subparagraph 3 in Section 6.0 of DAQ-2018-007709 should be deleted as the BACT review for space heaters in DAQ-2018-007161 Section 5D is applicable. Section 5.0 ofDAQ-2018-007709 should also be modified to indicate proper operations are already in place. Please see the SIP Evaluation Report markups provided in Appendix 1 of these comments.

KUC is therefore requesting a modification to the Part H limitation for the Tioga heaters. Condition j.ii.B of Part H.12 should be deleted.

Comment 4 Response:

UDAQ agrees that the BACT analysis for the Tioga Heaters in Section 2.2.1 of the TSD (DAQ-2018-007709) needs to reflect the BACT analysis prepared in Appendix A (DAQ-2018-007161) and a natural gas limitation is not an appropriate BACT determination for these units. The analysis for space heaters conducted in Section 5D of Appendix A was based on heaters with input ratings of 0.3 MMBtu/hr. The Tioga Heaters are significantly larger in size than the space heaters evaluated in Section 5D, so the analysis for boilers rated less than 10 MMBtu/hr in Section 5C of Appendix A will be used for this response.

Section 5C found that retrofitting burners or boiler replacement is not economically feasible for boilers under 5 MMBtu/hr. UDAQ recommended the use of natural gas as primary fuel and good combustion practices as BACT for existing boilers.

KUC evaluated the cost of heater replacement based on actual emission rates and estimated that replacement would cost $207,602 per ton of NO_x removed.

A natural gas limitation is an appropriate BACT limit if a unit's limited usage makes installation of controls economical infeasible. However, as stated in Section 5D of Appendix A, replacement of these units is not cost effective assuming maximum usage (i.e. 8,760 hrs/yr at full input rating capacity). This is supported by KUC's cost analysis for this unit. Therefore, UDAQ agrees that the natural gas limitation should not be considered BACT and should not be included in Part H.

UDAQ recommends that BACT for the Tioga Heaters is the use of natural gas as primary fuel and good combustion practices. No additional requirements or limits are required for these units.

UDAQ will remove the limit in Part H.12.j.ii.B for the Tioga Heaters.

<u>Comment 5:</u>

A review of the BACT analysis for the Roadbase Crushing and Screening Plant at the BCM is presented in DAQ-2018-007709. Emissions from roadbase crushing and screening are controlled by water sprays. The controls are consistent with the BACT evaluation in DAQ-2018-007161, Appendix A: BACT for Various Emissions Units at Stationary Sources.

Section 2.1.8 of DAQ-2018-007709 should be deleted as the BACT reviews for crushers, screens and transfers in DAQ-2018-007161 Sections 12A, 12B and 12I are applicable. Please see the SIP Evaluation Report markups provided in Appendix 1 of these comments.

Comment 5 Response:

The commenter stated that the roadbase crushing and screening plant is consistent with emissions units addressed by DAQ-2018-007161" and that the BACT review for the roadbase crushing and screening plant should be removed from the KUC BCM TSD document. DAQ-2018-007709, Appendix A to Part

H, includes a BACT analysis for crushers, transfer and drop points, and screens in Sections 12A, 12B, and 12I, respectively. As previously stated, Appendix A was created to more efficiently and consistently address BACT for small emission sources found in several major sources. However, these analyses were not intended to replace a discussion of small emission units in TSDs documents. UDAQ's objective was to include discussions of the small emission units in each TSD and make BACT determinations as recommended in Appendix A or based site-specific information.

The BACT determination in the KUC BCM TSD is consistent with the recommendations in Appendix A. No changes were made as a result of this comment.

<u>Comment 6:</u>
A review of the BACT analysis for the Feed and Product Dryer Oil Heaters at the Copperton Concentrator is presented in DAQ-2018-007709. The controls for these heaters are consistent with the BACT evaluation in DAQ-2018-007161, Appendix A: BACT for Various Emissions Units at Stationary Sources.

Section 2.1.13 and Subparagraph A in Section 6.0 ofDAQ-2018-007709 should be deleted as the BACT reviews in DAQ-2018-007161 Sections *SA* are applicable. Please see the SIP Evaluation Report markups provided in Appendix 1 of these comments.

KUC is therefore requesting a modification to the Part H limitations. Condition j.ii.A of Part H.12 should be deleted.

Comment 6 Response:

The commenter stated that the feed and product dryer oil heaters is consistent with emissions units addressed by DAQ-2018-007161 and that the BACT review for these heaters should be removed from the KUC BCM TSD document. As previously stated, Appendix A was created to more efficiently and consistently address BACT for small emission sources found in several major sources. However, these analyses were not intended to replace a discussion of small emission units in TSDs documents. UDAQ's objective was to include discussions of the small emission units in each TSD and make BACT determinations as recommended in Appendix A or based site-specific information.

The BACT determination in the KUC BCM TSD is consistent with the recommendations in Appendix A. No changes were made as a result of this comment.

H-43[submitted by Kennecott Utah Copper]: Smelter, Refinery, MAP *(see TOPIC 4: Specific Comments on Other Part H.12 Conditions and SIP Evaluation Reports)*:

Response to H-43:

<u>Comment 7:</u>
Markups to the SIP Evaluation Report DAQ-2018-007702, included as Appendix 1 of these comments, include corrections to the description of the sources at the Smelter, Refinery and MAP facilities. Facility descriptions in Sections 1.2, 2.3, 2.3.2, 2.3.5, 3.0, 5.2 and 6.0 have been modified to correct inaccuracies.

Comment 7 Response:

The corrections proposed by the commenter could not be incorporated since the TSD is not being revised as part of this response to comment process. UDAQ will addresses these proposed corrections in general terms for each section mentioned in this comment. Some of these corrections were addressed in other responses, as noted below.

1.2 Facility Process Summary

Third paragraph of Section 1.2 should read: "KUC permitted the MAP plant that was schedule to begin operation in 2014 but KUC has permanently ceased construction on this project. No evaluation of the facility and the permitted equipment is required."

Seventh paragraph, last sentence of Section 1.2 should read: "AO DAQE-AN0103460054-14 was issued to incorporate a crushing and screening plant. No other modifications were made to the Smelter AO in the last 5 years."

Ninth paragraph of Section 1.2 described permitting actions associated with the MAP and is no longer relevant since MAP construction has ceased.

2.3 Facility Process Summary

See Response to H-43, Comment 11.

2.3.2 Powerhouse Holman Boiler

See Response to H-43, Comment 9.

2.3.5 Feed Storage Building

The second sentence in the process description should read: "Particulate matter from loading materials into the feed storage building is vented to a baghouse."

3.0 Consideration of Ammonia

See Response to H-43, Comment 10.

5.2 Smelter

UDAQ agrees that this section should be deleted as it refers to the implementation of controls that were ultimately not required as BACT.

6.0 New $PM_{2.5}$ SIP – KUC Smelter and Refinery Specific Requirements

See Response to H-43, Comment 12.

UDAQ revised Part H.12.l.B to add CEMS to the limits associated to the Holman Boiler.

Comment 8:

The SIP Evaluation Report DAQ-2018-007702 does not clearly state actual emissions used in the BACT analysis. For example, UDAQ has identified 2014 actual emissions as calendar year 2016 emissions. Additionally, the PTE emissions summaries for $PM_{2.5}$ do not include the condensable portion of emissions but actual emissions represent total $PM_{2.5}$ emissions do include the condensable fraction and are therefore inconsistent. Emissions summaries in Sections

1.3, 1.4, 2.1, 2.1.1 and 2.1.3 should be modified to correctly summarize facility emissions. Please see the SIP Evaluation Report markups provided in Appendix 1 of these comments.

Comment 8 Response:

UDAQ agrees that there were some errors in the emissions listed in the TSD document. The following are the correct emissions for the Refinery Smelter.

<u>1.3 Facility Baseline Emissions</u>

Site-wide 2016 actual emissions (tons/yr) for Refinery and Smelter.

$PM_{2.5}$*	NO_x	SO_2	VOC	NH_3
205.45	140.33	735.29	9.74	8.63

*$PM_{2.5}$ includes filterable + condensable

<u>1.4 Facility Criteria Air Pollutant Emissions Sources</u>

Emission Unit	$PM_{2.5}$[1] (filterable only)	NO_x	SO_2	VOC	NH_3
Refinery[2]	25.64	38.57	4.44	8.42	0.61
Smelter[3]	426.35	185.29	1,085.72	13.50	8.63
Total	**451.99**	**223.86**	**1090.16**	**21.92**	**9.24**

[1]The $PM_{2.5}$ PTE totals do not include condensable particulate emissions, unlike the baseline emissions presented in Section 1.3.
[2]PTE from DAQE-AN0103460045-10
[3]PTE from DAQE-AN103460053-14

<u>2.1 Emission Unit (EU) and Existing Controls</u>

<u>Refinery PTEs</u>

Emission Unit	$PM_{2.5}$[1] (filterable only)	NO_x	SO_2	VOC	NH_3
Boilers	1.22	8.31	0.1	0.88	0.61
CHP Unit	8.68	29.79	1.20	6.7	0.32
Cooling Towers	5.5				
Propane Communications Generator		0.28		0.04	
Degreasers				0.06	
Fueling Stations				0.24	
Emergency Generator	0.013	0.181	0.01	0.015	
Soda Ash Storage Silo	0.05				
Precious Metal Packaging Area	2				
Hydrometallurgical Precious Metals Processing	2.7		3.10		

Hydrometallurgical Silver Production					0.61
Tankhouse Sources	1.92				
Total	**22.08**	**38.56**	**4.41**	**7.94**	**1.54**

[1]The $PM_{2.5}$ PTE totals do not include condensable particulate emissions, unlike the baseline emissions presented in Section 1.3.

The Table above also serves to correct the PTEs listed in Section 2.1.1 and 2.1.3.

2.3 Emission Unit (EU) and Existing Controls

Smelter PTEs

Emission Unit	**$PM_{2.5}$ (filterable only)**	**NO_x**	**SO_2**	**VOC**	**NH_3**
Main Stack	372.3	153.3	924.18	2.8	
Powerhouse Holman Boiler	2.09	24.09	0.25	0.59	
Matte and Slag Granulators	13.4		7.88		
Feed Storage Building	62.61				
Anode Area Fugitives		2.31			
Smelter fugitives			157.00		
Acid Plant fugitives	0.47		0.16		
Powerhouse Foster Wheeler Boiler[2]	2.01	23.17	0.24	0.56	
Storage Piles/Loadout	2.15				
Slag Concentrator	3				
Smelter Cooling Tower	0.03				
Ground Matte Silo	1.2				
Molding Coating Storage Silo	1.2				
Lime Storage Silos	2.4				
Recycle and Crushing Building	0.11				
Smelter Lab	1.8				
Cold Solvent Degreasers				1	
Fueling Stations				0.17	
Diesel Emergency Generator	0.03	3.93	0.06	0.11	
Total	**462.79**	**183.63**	**1,089.53**	**4.67**	**0**

[1]The $PM_{2.5}$ PTE totals do not include condensable particulate emissions, unlike the baseline emissions presented in Section 1.3.

[2]Foster Wheeler Boiler vents to main stack, emissions included for informational purposes only.

Comment 9:

The SIP Evaluation Report for the Combined Heat and Power Unit at the Refinery and the Holman Boiler and Foster Wheeler Boiler at the Smelter presented in DAQ-2018-007702 should be revised. In

May 2018, KUC submitted revised economic feasibility analysis for the BACT determinations for these emission sources. The information presented in Sections 2.1.2, 2.3.2 and 2.3.9 ofDAQ-2018-007702 is not accurate and should be revised with updated cost information.

Comment 9 Response:

The commenter proposed to revise the text regarding the economic feasibility of replacing the Holman Boiler (Section 2.3.2) and the Powerhouse Foster Wheeler Boilers (Section 2.3.9). The commenter proposed to only include the final costs provided to UDAQ in May 2018 in these sections. These revisions will not change the BACT determination for the Holman Boiler and will therefore, not be incorporated.

It is not clear what corrections the commenter proposed for Section 2.1.2 for the CHP unit, so no changes were made.

Comment 10:

The addition of SCR for NO_x control was found to be economically infeasible for the Holman and Foster Wheeler boilers at the Smelter and Combined Heat and Power Unit at the Refinery. Section 3.0 of DAQ-2018-007702 incorrectly references SCRs and ammonia slip. All references to SCR in Section 3.0 should be deleted.

Hydrometallurgical Silver Production is a source of ammonia; however the relevant BACT information was omitted from Section 3.0. BACT discussion regarding ammonia emissions from the Hydrometallurgical Silver Production scrubber has been added to Section 3.0. Please see the SIP Evaluation Report markups provided in Appendix 1 of these comments.

Comment 10 Response:

UDAQ agrees that Section 3.0 of DAQ-2018-007702 incorrectly states that SCRs will be installed on the CHP combustion turbine. The BACT evaluation in Section 3.0 of DAQ-2018-007702 focused on ammonia slip from SCRs. Since SCRs are not being installed at the Refinery and Smelter, the BACT analysis included in Section 3.0 is not pertinent to the emission units at this source.

The only sources of ammonia emissions at the Refinery and Smelter are natural gas combustion and the Hydrometallurgical Silver Production. Only ammonia emissions from Hydrometallurgical Silver Production can be controlled.

The following is the corrected text for Section 3.0.

3.0 Consideration of Ammonia

The only sources of ammonia emissions at the Refinery and the Smelter are the combustion of natural gas and the Hydrometallurgical Silver Production. The only source of ammonia emissions that can be controlled is the ammonia from the Hydrometallurgical Silver Production, which is controlled by a scrubber. The potential ammonia emissions from the Hydrometallurgical Silver Production are estimated at 0.61 tpy.

The unreacted ammonia can be treated as a $PM_{2.5}$ precursor. Although ammonia was previously not considered as a precursor pollutant in Utah's $PM_{2.5}$ Serious SIP, and the source's BACT analysis did not include an analysis of BACT for ammonia emissions, an analysis is being included here for completeness.

Control Options:

Most of the controls for ammonia in the EPA's RBLC database are related to ammonia slip from SCRs/SNCR. A scrubber with 85% removal efficiency was listed as an add-on control technology for ammonia emissions from storage tanks.

According to EPA's *"Control and Pollution Prevention Options for Ammonia Emissions"* (EPA-456/R-95-002, April 1995), a wet scrubber is the only add-on control system available for ammonia emissions. Other prevention techniques, such as limiting ammonia input, capture systems, and good maintenance practices are also identified.

Technological Feasibility:

Wet scrubbers are the only technically feasible option identified.

Economic Feasibility:

All control technologies are economically feasible. Therefore, an economic feasibility was not performed.

BACT Selection:

BACT for ammonia emissions from the Hydrometallurgical Silver Production is the use of scrubbers. Scrubbers are both technically and economically feasible options.

Implementation Schedule:

Proper controls are already in place.

Startup/Shutdown Considerations

There are no startup/shutdown operations to be considered for this source.

Comment 11:

DAQ-2018-007161, Appendix A: BACT for Various Emissions Units at Stationary Sources includes emissions units/processes operating at the Smelter. The following sources at the Smelter are covered by the Appendix A BACT review and meet the specified BACT requirements in each section:

- Miscellaneous Storage Piles/Loadout, Section 12J
- Ground Matte Silo, Section 3
- Mold Coatings Storage Silo, Section 3
- Lime Storage Silo, Section 11
- Limestone Storage Silo, Section 11
- Smelter Laboratory, Section 3 and 10
- Propane Communications Generator, Section 8E
- Cold Solvent Degreaser, Section 4
- Gasoline Fueling Stations, Section 13B
- Diesel Emergency Generator for Pyrometallurgical, Section 8C
- Space Heaters, Section, Section 5D

Since the above mentioned BACT reviews from DAQ-2018-007161 are applicable, and KUC has implemented BACT controls for each source, the following sections should be deleted from DAQ-2018-007702: 2.3.10, 2.3.13, 2.3.14, 2.3.15, 2.3.16, 2.3.17, and 2.3.18. Please see the SIP Evaluation Report markups provided in Appendix 1 of these comments.

Comment 11 Response:

The commenter stated that the equipment listed above is consistent with emissions units addressed by DAQ-2018-007161 and that the BACT review for these heaters should be removed from the KUC BCM TSD document. As previously stated, Appendix A was created to more efficiently and consistently address BACT for small emission sources found in several major sources. However, these analyses were not intended to replace a discussion of small emission units in TSDs documents. UDAQ's objective was to include discussions of the small emission units in each TSD and make BACT determinations as recommended in Appendix A or based site-specific information.

No changes were made as a result of this comment.

Comment 12:
The BACT analysis presented in Section 2.3.2 for installation of Ultra Low NO_x Burners on the Holman Boiler indicates that the upgrade is not cost effective. Accordingly, Sections 4.1 and 5.2 ofDAQ-2018-007702 should be deleted and Section 6.0 n.i.A.II Holman Boiler NO_x limit should remain 14 lblhr (calendar day average) as the change in emissions limitation was not established as part of the BACT process. Condition 1.i.A.II of SIP Part H.12, NO_x limit should also be revised back to 14lb/hr (calendar day average). Please see the SIP Evaluation Report markups provided in Appendix 1 of these comments.

Comment 12 Response:
UDAQ agrees that the NO_x emission limit of 9 lb/hr for the Holman Boiler was not appropriately justified in the BACT analysis in DAQ-2018-007702. Since no data is available to support the 9 lb/hr limit, UDAQ will change this limit in Condition 1.i.A.II of SIP Part H.12 to the original limit of 14 lb/hr.

Comment 13:
DAQE-2018-007702 includes discussions of the MAP facility in Sections 1.2 and 1.4. All discussions related to MAP should be deleted. Please see the SIP Evaluation Report markups provided in Appendix 1 of these comments.

Comment 13 Response:
UDAQ could not incorporate the proposed changes since the TSD is not being revised as part of this response to comment process. UDAQ agrees that discussions related to the MAP should not have been included in the TSD document since construction of the MAP has permanently been ceased.

H-44[submitted by Kennecott Utah Copper]: Utah Power Plant, Tailings and Laboratory *(see TOPIC 4: Specific Comments on Other Part H.12 Conditions and SIP Evaluation Reports)*:

Response to H-44:

Comment 14:
Markups to the SIP Evaluation Report DAQ-2018-007701, included as Appendix 1 of these comments, include corrections to the description of the sources at UPP and the Tailings impoundment. Facility descriptions in Section 1.2 and 2.1.1 have been modified to correct inaccuracies.

Comment 14 Response:
The corrections proposed by the commenter could not be incorporated since the TSD is not being revised as part of this response to comment process. No substantial revisions were proposed to Section 1.2 so no changes were made.

The changes proposed to Section 2.1.1 are addressed in Responses to H-29 through H-34.

Comment 15:
The SIP Evaluation Report DAQ-2018-007701 does not clearly state actual emissions used in the BACT analysis. For example, UDAQ has identified 2014 actual emissions as calendar year 2016 emissions. Additionally, the PTE emissions summaries for $PM_{2.5}$ do not include the condensable portion of emissions but actual emissions represent total $PM_{2.5}$ emissions do include the condensable fraction and are therefore inconsistent. Emissions summaries in Sections 1.3, 1.4, and 2.1.1 should be modified to correctly summarize UPP emissions. Please see the SIP Evaluation Report markups provided in Appendix 1 of these comments.

Comment 15 Response:
UDAQ agrees that there were some errors in the emissions listed in the TSD document. The following are the correct emission for the UPP.

1.3 Facility Baseline Emissions

Site-wide 2016 actual emissions (tons/yr) for UPP.

$PM_{2.5}$*	NO_x	SO_2	VOC	NH_3
117.86	1,172.29	2,151.94	8.42	0.64

*$PM_{2.5}$ includes filterable + condensable

1.4 Facility Criteria Air Pollutant Emissions Sources

Emission Unit	**$PM_{2.5}$**[1] **(filterable only)**	**NO_x**	**SO_2**	**VOC**	**NH_3**
Power Plant	165	1,635	2,577.06	40	0.24
Tailings Impoundment	5.44	0.28	<0.01	4.00	0.00
Laboratory	0.06	0.54	0.01	0.10	0.01
Total	**170.5**	**1,636**	**2,577.07**	**44.1**	**0.25**

[1]The $PM_{2.5}$ PTE totals do not include condensable particulate emissions, unlike the baseline emissions presented in Section 1.3.

2.1.1 Unit 4 Boiler
The PTE for Unit 4 are as follows:

	$PM_{2.5}$ (filterable + condensable)	**NO_x**	**SO_2**	**VOC**
Coal	74.85	1,108	2,562	3.96
Natural Gas	6.25	441	0.80	7.35

The 2016 actual emissions (tons/yr) for Unit 4 are as follows:

$PM_{2.5}$ (filterable + condensable)	**NO_x**	**SO_2**	**VOC**	**NH_3**

Coal	68	539.54	1330.01	4.38	0.041
Natural Gas	0.96	17.56	0.09	0.81	0.47

2.1.2 Unit 5 Boiler

The PTE (tons/yr) for Unit 5 as permitted in AO DAQE-AN105720031-15 dated November 10, 2015 is listed below:

$PM_{2.5}$ (filterable + condensable)	**NO_x**	**SO_2**	**VOC**
72.2	72.6	13.8	25

Comment 16:

Previous SIP determinations for UPP Unit 4 operating on natural gas during the winter months from November 1st to March 1st required the installation of LNB, OFA and SCR for NO_x controls. Since the top control technology is already required no further analysis is necessary. Section 2.1.1 ofDAQ-2018-007701 should be modified to accurately indicate the top controls for NO_x are already required. Please see the SIP Evaluation Report markups provided in Appendix 1 of these comments.

Comment 16 Response:

In 2014, the Part H limits for $PM_{2.5}$ Moderate SIP were adopted. A Reasonably Available Control Technology (RACT) analysis was done to determine the Part H limits for this SIP. As part of this evaluation, UDAQ identified the installation of an LNB/OFA system with an SCR system as RACT for Unit 4. Part H.2.h.i.D.II of the $PM_{2.5}$ Moderate SIP required that after January 1, 2018, Unit 4 meet a NO_x emission limit of 60 ppmvd for the period between November 1 to February 28/29.

The $PM_{2.5}$ implementation rule requires that existing sources of all $PM_{2.5}$ precursors in the area are subject to evaluation for BACM/BACT control measures, i.e. the more stringent regulatory requirement. Therefore, UDAQ re-evaluated the RACT limits for Unit 4 as part of the BACT analysis for this Serious $PM_{2.5}$ SIP. As part of this BACT review, UDAQ identified that the maximum degree of reduction from an LNB/OFA system is 50% and 90% from an SCR system. UDAQ applied these reduction efficiencies as shown in the table below to derive the 20 ppmvd limit.

The commenter suggested that the BACT analysis be modified to state that the top control technology is already required, so a BACT analysis is not required. This would essentially return the NO_x limit for Unit #4 to the RACT limit of 60 ppmvd established as RACT for the 2014 Moderate $PM_{2.5}$ SIP. UDAQ disagrees with this suggestion. UDAQ conducted a BACT review for each emission units for all major sources, as required in the $PM_{2.5}$ implementation rule. UDAQ re-evaluated the RACT limit for Unit #4 as part of this BACT analysis and determined that a NO_x limit of 20 ppmvd is technically and economically feasible. The commenter did not provide any documentation to demonstrate that the 20 ppmvd limit is not a feasible option. Rather, the commenter simply suggested that UDAQ rescind the limit established in the BACT analysis. Since a BACT analysis is a requirement of the $PM_{2.5}$ implementation rule for serious $PM_{2.5}$ nonattainment areas, UDAQ will not make this change.

Comment 17:

Per discussion in Topic 1 of these comments, Unit 4 operates with seasonal variability. Unit 4 shall be operated on natural gas during the winter months between the months of November 1 and February 28/29. Section 2.1, Section 3.1, Section 4.1 and Section 5.0 ofDAQ-2018-2007701 should be modified to accurately describe the seasonal natural gas operation and controls review of Unit 4. Please see the SIP Evaluation Report markups provided in Appendix 1 of these comments.

Comment 17 Response:
See Responses to H-29 through H-34.

Comment 18:
SCRs are operated per manufactures' recommendations and no control technologies exist to minimize ammonia slip. Control Options, Technological Feasibility, Economic Feasibility and BACT Selection paragraphs in Section 2.3 of DAQ-2018-007701 should be modified to indicate control technologies for minimizing emissions from ammonia slip include proper design of the equipment and operating the SCR per manufacturers' recommendations. There are no additional identified control technologies for minimizing emissions from ammonia slip to those listed above. Please see the SIP Evaluation Report markups provided in Appendix 1 of these comments.

Comment 18 Response:
Ammonia slip from SCRs is a potential source of ammonia emissions. However, the likelihood of being able to pin it down to an exact range is difficult as the SCR unit has not been installed and tested at this time. Therefore, determining an appropriate ammonia slip limitation would not be effective in ensuring compliance and proper source operation as it is new equipment. Commenter correctly stated that there are no control technologies for minimizing emissions of ammonia slip but failed to provide any documentation or suggested ammonia slip limitations specific to Unit 4 for this analysis. In order to select a BACT option, UDAQ will review and establish an ammonia slip limit through an Approval Order as well as the Title V Operating Permit.

Comment 19:
KUC identified inaccurate information in various locations in the SIP Evaluation Reports (DAQ-2018-007709, DAQ-2018-007702 and DAQ-2018-007701) related to our operations. In addition to those specified in the previous comments, further markups on the reports are provided in Appendix 1 of these comments.

Comment 19 Response:
The corrections incorporated are indicated in Response to H-42, H-43, and H-44.

Comments Submitted by Western Resource Advocates, Utah Chapter of Sierra Club, Utah Physicians for a Healthy Environment, and Heal Utah

H-45[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, and Heal Utah]:
Legal Analysis of Section IX, Part H, Emissions Limits and Operating Practices, of the Utah State Implementation Plan. *(see Section I. Background Comments)*

Comment 1:
The Director Must Derive and Implement BACM.

Comment 2:
The Director's BACT Review Must be Robust and Must Lead to a Defensible Emission Unit Specific Limitation.

Comment 3:
BACT Must Lead to an Emission Unit Specific Emission Limit.

Comment 4:
BACT Includes Any Feasible Technologies that Can Be Partially or Fully Implemented by December 31, 2019.

Comment 5:
BACT Represents the Maximum Reduction of Emissions Achievable.

Comment 6:
BACM is "Generally Independent" of Attainment.

Comment 7:
Measures Adopted in Other States Are Assumed to be Technologically Feasible.

Comment 8:
BACT Will Be More Expensive than RACT.

Comment 9:
The Director Must Also Consider Control Technologies that Have Not Been Implemented Elsewhere.

Response to H-45:
DAQ acknowledges the commenters' review of the Implementation Rule and other pertinent requirements.

H-46[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, and Heal Utah]:
BACT for the Salt Lake NAA Is Not Legally Sufficient. *(see Section II. Specific Comments)*

Despite these rigorous requirements, the Director failed to derive and implement BACT for major sources in the Salt Lake NAA, relying chiefly on technology and practices adopted as RACM/RACT. In so adopting RACM/RACT as BACT and failing to require legally sufficient BACT, the Director has not: 1) showed that he has developed and imposed emission-unit-specific emission limits that represent the maximum achievable reductions of emissions of $PM_{2.5}$ and $PM_{2.5}$ precursors; 2) produced a complete review of technology adopted in other states and for other similar facilities and emission units; 3) established why technologies adopted in other states and for other facilities and emission units are not technologically or economically feasible; 4) applied BACT's "higher economic costs" analysis; and 5) provided objective data to support his contentions.

Response to H-46: UDAQ disagrees with the commenter. In re-reviewing the control measures included as RACM in Utah's Moderate Area PM2.5 SIP for the SLC nonattainment area, it was determined that in most cases these measures were in fact already stringent enough so as to also meet BACM. During the development of the moderate area PM2.5 SIP, UDAQ was well aware of the potential possibility of eventually being reclassified as a serious nonattainment area. UDAQ was in communication with EPA throughout the development process and had discussed the possibility and potential consequences throughout that development period. During negotiations with the listed sources, UDAQ always made clear to them that they should view potential controls as being "better than RACT" and to "focus on BACT-level controls." UDAQ knew and explained that potentially revisiting this issue with the possibility of replacing "just installed" controls would be an expensive and unpopular undertaking – so better to focus on the higher level of control from the outset.
Utah's review of potential controls entails measures that address primary PM2.5 and precursors to secondary PM2.5, reveals a canvassing of other states, addresses technological and economic feasibility, concludes that the cost benefit in terms of dollars spent per ton of emissions reduced is consistent with contemporary BACT analyses. This is documented in the materials provided as technical support.
The commenter's contention that Utah has not included every control measure implemented in any other state is more consistent with the idea of Most Stringent Measures (MSM) than BACM. MSM is not required for the SLC nonattainment area.

H-47[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, and Heal Utah]:
The Director Improperly Relies on NSPS as BACT for the Refineries. *(see Section II. Specific Comments)*

In addition, the Director relies heavily on New Source Performance Standards (NSPS) as BACT for the Salt Lake NAA refineries. However, by rule, the refinery NSPS, 40 C.F.R. 60.100a to 109a (Subpart Ja) reflects "best demonstrated technology" that is available and cost-effective for *all* refineries in the nation. 73 Fed. Reg. 35838, 35839 (June 24, 2008). Thus, the NSPS do not rise to the level of BACT – particularly without a robust analysis as to why more restrictive controls and emission limits adopted elsewhere are not warranted. As EPA's and Utah's BACT Rule make clear, NSPS necessarily provides the *floor* for a BACT emission limitation. *New Source Review Manual*, B.12 ("NSPS simply defines the minimal level of control to be considered in the BACT analysis."). A defensible FCCU BACT emission limitation, therefore, starts with Subpart Ja and considers more rigorous controls that those imposed by Subpart Ja.

Response to H-47: UDAQ disagrees with this comment. The commenter misunderstands the intent of both the technical support documents and the organizational structure of the SIP. UDAQ has elected to take a more innovative approach with respect to BACT for certain listed sources. The reasons for this are discussed elsewhere (please see UDAQ's response to Comment H-50 below), and will not be addressed here. This approach was begun during development of the moderate nonattainment area PM2.5 SIP and retained during development of the other recent particulate SIPs. Certain historical requirements that applied to all refineries, such as installing and operating 90% efficient SRUs, needed to be retained. Testing, monitoring, recordkeeping, reporting, and other requirements were the same as those being imposed on all other listed SIP sources. Gradually, the development of a "general requirements" section (proposed section IX.H.11) took shape – and all common requirements were moved into it to avoid repetition, transcription errors, and to increase commonality and fairness in application.

General refinery minimums were also developed or were brought forward. Some of these were existing items like the previously mentioned SRU requirement. Others were concepts like imposing the limits of NSPS Subparts Ja and GGGa on the refineries across the board – even if those subparts did not apply to the individual refinery yet. In some cases, moderate SIP RACM/RACT that could be applied to all the refineries as a group was also moved into the general requirements, such as the flaring and cooling tower requirements.

However, these are still to be viewed as minimums that all refineries located in the PM2.5 nonattainment area must meet – this applies whether the refinery is an existing listed SIP source, or a proposed new source. The requirements of IX.H.11 should still be viewed as the "floor" and not as final BACT. Lower emission limits are certainly possible when applied to an individual refinery. For example, the emission limits appearing in section IX.H.11.g.ii for refinery fuel gas represent the minimums that any refinery located within, or affecting any PM2.5 nonattainment area (or seeking to do so in the future) must meet – even prior to the application of BACT. The wording in the technical support documentation prepared by UDAQ may imply that this represents the maximum required. Instead, that language is simply meant to state that the source's selection of BACT meets the minimum requirement of IX.H.11 and is acceptable to UDAQ.

Each source goes beyond the minimums of IX.H.11 by installing and operating additional controls in order to meet the plant-wide emission caps and other work practice standards listed in the technical support. So that this is more clearly expressed in the language of IX.H.12, and to explicitly state the requirement that BACM/BACT is required on specific equipment (or in specific areas of the plant), UDAQ is adding additional requirements which list the control equipment and/or techniques specific to each refinery. These new requirements are included at the end of each refinery's individual subsection in IX.H.12 (this is also duplicated in IX.H.2 since the intent is to replicate these requirements as much as possible). There is also an associated installation date of 12/31/2018 which demonstrates that in order for UDAQ to claim credit for these BACT controls, all changes must have been made by the first of the year containing the regulatory attainment date (see 40 CFR 51.1011(b)(5)).

H-48[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, and Heal Utah]: The Director failed to require adequate reporting and recordkeeping requirements in the SIP contrary to the Clean Air Act and federal regulations. *See* Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements, 81 Fed. Reg. 58,010, 58,133 (Aug. 25, 2016). Specifically, the Director's proposed SIP: (1) authorizes sources to maintain compliance records that are not available to the public; (2) allows sources to take years to report failures to meet SIP terms and conditions; and (3) fails to require sufficient recording keeping and reporting to establish continuous compliance, often mandating instead only that the sources report non-compliance. *See* WRA Comments at 8 (unnumbered page). Specifically, the Director did not impose electronic reporting and record retention requirements with reports showing continuous compliance available online to be accessed by the general public. *See id*.

Response to H-48: There are two parts to this comment: (1) failure to make reports available to the public and (2) failure to impose reporting requirements that establish continuous compliance. The proposed SIP imposes legally sufficient recordkeeping and reporting requirements and is compliant with the federal law. UDAQ addresses each of the commenter's arguments in turn.

<u>Availability of Reports to the Public</u>

The proposed SIP contains the following general recordkeeping and reporting requirement:

> 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.

Utah State Implementation Plan, Emission Limits and Operating Practices, Section IX, Part H (SIP Part H) at 50, Subsection H.11.c.i (requirement for $PM_{2.5}$). In addition, certain sources and source categories in the proposed SIP are subject to federal recordkeeping and reporting requirements. *See id*; at 52-53, Subsection H.11.g.ii.A ($PM_{2.}$5 portion: Petroleum Refineries: Limits on Refinery Fuel Gas), at 95, Subsection H.12.o.iii.C (Tesoro Refining and Marketing Company: Salt Lake City Refinery: Source-wide SO_2 Cap: Fuel Gas or SO_2 emissions monitoring, recordkeeping, and reporting requirements).

EPA's rule on particulate matter SIP requirements mandates that the regulations adopted into a SIP include reporting and record retention requirements i.e. "criteria for retaining monitoring and test data in an electronic form and periodic electronic reporting of information as needed to the compliance office." 81 Fed. Reg. at 58,133. EPA further encourages electronic records retention for easier access and trend-spotting for regulators. *See id*. As far as the public access requirements, EPA "*recommends* that *compliance reports* [not the actual electronic records showing continuous compliance] be made available online" for the general public to access without filing a records request with a regulator agency. *Id*. (emphasis added).

The proposed SIP recordkeeping condition is fully compliant with this requirement. All sources subject to SIP must record information demonstrating compliance "for all periods when the source is in operation." SIP Part H, at 50, Subsection H.11.c.i (requirement for $PM_{2.5}$). The sources monitor and record such data and provide this information to UDAQ at its request. UDAQ reviews the information and those reports are available online for the general public at http://eqedocs.utah.gov/. Note also that availability of such reports to the public is not a mandate but simply a recommendation by EPA. There is also a clear distinction in the regulation between the continuously monitored and recorded data and compliance reports that EPA suggests a regulator make available online.

Federal recordkeeping and reporting requirements cited in the proposed SIP as applicable to specific source categories also satisfy the requirement of retaining and recording monitoring data. Section 60.108a of the Part 40, Subpart Ja, for example, lists specific monitoring and recording requirements applicable to petroleum refineries.

Adequacy of Compliance Reporting

The second general recordkeeping and reporting requirement in the proposed SIP places an obligation on the sources subject to SIP to comply with emission inventories rule, Utah Admin. Code R307-150, to submit reports for any deviations from the SIP requirements, including upset conditions, and to follow Rule R307-107 of the Utah Administrative Code for breakdowns. *See* SIP Part H at 50, Subsection H.11.c.ii (requirement for $PM_{2.5}$).

The commenter takes issue with these provisions because they require reporting of non-compliant conditions within 24 months. In commenter's view this is contrary to the federal requirement that the sources demonstrate compliance on a continuous basis. The commenter is incorrect in its interpretation of the federal regulation and its understanding of the state's reporting requirements.

EPA's rule does not contain any specific periodic reporting requirements but instead requires only that "recordkeeping and monitoring . . . [are] sufficient to enable the state or the EPA to determine whether the source is complying with the emission limit on a continuous basis." 81 Fed. Reg. at 58,133. The proposed SIP contains such recordkeeping requirements as discussed above, including a requirement for recording data for all periods of operation. Monitoring requirements in the proposed SIP are also compliant with the federal rule where UDAQ included methods for monitoring compliance for each source or categories of sources subject to SIP. Such methods include periodic stack testing, continuous monitoring of emissions and opacity, daily monitoring of natural gas and fuel oil consumption for petroleum refineries, continuous emission monitoring systems (CEMs) for NO_x and CO for power plants, calculation of 24-hour emission limits, calculation of daily emissions, and determinations through laboratory testing onsite.

Additionally, the commenter overlooks the language in the SIP that requires deviation reports to be "submitted to the Director no later than 24-months following the deviation *or earlier if specified by an underlying applicable requirement*." SIP Part H at 50, Subsection H.11.c.ii (requirement for $PM_{2.5}$) (emphasis added). These underlying requirements may shorten the submission time.

H-49[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, and Heal Utah]: The Director Failed to Require Adequate Reporting and Recordkeeping Requirements *(see Section II. Specific Comments)*

The Salt Lake City NAA has failed to attain the 24-hour PM2.5 NAAQS by the serious attainment date. The 24-hour PM2.5 standard – or "short-term" standard – is intended, by law, to protect "against health effects associated with **short-term** PM2.5 exposures, especially in areas with high peak PM2.5 concentrations." 80 Fed. Reg. 15340, 15347 (March 23, 2015) (emphasis added). EPA determined that the 24-hour PM2.5 NAAQS is necessary to "provide[] increased public health protection, including the health of at-risk populations which include children, older adults, persons with pre-existing health and lung disease and persons of lower socioeconomic status, against a broad range of PM2.5-related effects that include premature mortality, increased hospital admissions and emergency department visits, and development of chronic respiratory disease."
Id.

Only short-term emission limits – with averaging periods of 24 hours or less – are adequate to prevent short-term spikes in air pollution. *NSR Manual* B.56 ("BACT emission limits…must...demonstrate protection of short-term ambient standards (limits written in pounds/hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements).").

As the Utah Supreme Court explained, the goals of BACT emission limitations are: "(1) to achieve the lowest percent reduction, (2) to protect short-term ambient standards, and (3) to be enforceable as a practical matter." *Utah Chapter of the Sierra Club v. Air Quality Board*, 2009 UT 76, ¶ 4, 226 P.3d 719 (citing EPA, New Source Review Workshop Manual, B.6-.9). Here, in addition to other longer-term emission limitations, limits that are averaged over periods of 24 hours or less are a necessary component of a SIP that addresses violations of the 24-hour PM2.5 NAAQS. Limitations averaged over periods longer than 24 hours – such as 7 days, 30 days or 365 days – do not prevent sharp increases in emissions over the short-term and thus do not sufficient protect the 24-hour NAAQS.

As EPA explained when it commented on Utah's Moderate PM2.5 SIPs, "[u]nder a long-term limit, emissions from a source can spike during a short-term period." EPA Region 8 Comments on Utah's Proposed [Moderate] PM2.5 State Implementation Plans and Technical Support Documents at 8 (Oct. 30, 2014). The agency expounded that, for example, "[a]n emission limit expressed as a 30-day average allows significantly higher short-term emissions that can impact a short-term standard such as the 24-hour PM2.5 NAAQS." *Id.* at 24.

Short-term emission limitations, as averaged over a period of 24 hours or less, are also necessary to reflect BACT – "the maximum degree of emission reduction achievable… considering energy, economic and environmental impacts and other costs." 81 Fed. Reg. at 58081. Without analysis in the record, the Director cannot show that an emission limit averaged over a period longer than 24-hours and therefore allows short-term spikes in emissions is indeed BACT when compared to a short-term emission limit that prevents short terms spikes. *See Sierra Club v. Air Quality Board*, 2009 UT at ¶ 4 (determining the goals of BACT emission limitations as being: "(1) to achieve the lowest percent reduction, (2) to protect short-term ambient standards, and (3) to be enforceable as a practical matter.").

Response to H-49: UDAQ agrees with this comment in part. Short-term emission limits, i.e. those with averaging periods of 24-hours or less are needed to demonstrate attainment of the NAAQS. Many of these limitations were already present in the SIP. Other limits, which may not have been directly expressed on a 24-hour or less averaging period are considered instantaneous limits – to be met at all times, and it is the mechanism of monitoring which ensures compliance with that limitation. The refineries use continuous H2S monitors to measure sulfur content of fuel gas, such monitors are averaged on a 1-hour basis, and the results included in each refinery's total SO2 emissions. In some cases, a given source may have two limits working in concert. For example, both the PacifiCorp Gadsby Power Plant and the UMPA West Valley Power Plant have concentration limits (expressed as ppm) in addition to existing lb/hr limits. Although the concentration limit may have a longer averaging period (perhaps as long as a rolling 30-day average), this is not problematic. The purpose of the concentration limitation is to show proper operation and maintenance of the control device over the lifetime of the unit. While it is the lb/hr (mass-based) limit which demonstrates how that unit at the source helps in attaining the NAAQS – and the mass-based limit remains on a 24-hr or less averaging period.

H-50[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, and Heal Utah]: The Director's Reliance on Plant-Wide Caps is Unlawful and Lacks Record Support. *(see Section II. Specific Comments)*

As explained above, adequate BACT analysis must lead to an emission limitation for each emission unit. Therefore, the Director's reliance on plant-wide caps to represent a BACT emission limit is contrary to the law. Rather, the Director must undertake BACT analysis for each emission unit and derive a defensible emission limit for that unit. That emission limit must represent the maximum achievable reduction of emission from that unit and must be practically enforceable. Without emission unit specific analysis and corresponding emission limits, the Director's BACT fails to establish that limits he adopted as BACT reflect "the maximum degree of emission reduction achievable[.]" 81 Fed. Reg. at 58081. Rather than meeting the requirements of BACT, the Director has in several instances proposed plant-wide caps without providing any explanation or documentation showing how those caps represent BACT. As a result, the Director's BACT fails to comply with the law.

Even if it were permissible to rely on source-wide caps in Subpart H, to comply with BACT, the Director must determine, based on record evidence, unit-specific emission limits reflective of BACT and only then use those emission limits and any unit-specific capacity factors to develop plant-wide caps that reflect BACT. The record must reflect that this analysis complies with BACT, including by providing adequate documentation. However, the Director has not provided this documentation and analysis and so fails to explain how his proposed source-wide caps reflect unit-specific BACT controls and/or corresponding emission limitations. Thus, there is an unlawful disconnect between the controls and emission limits proposed by the sources and the plant-wide caps the Director has adopted purportedly as BACT.

Further, there must be an explicit and specific enforceable measure included in Subpart H for any emission factor used to establish (and/or to be used to establish compliance with) a plant-wide cap. For example, in cases where the Director has imposed plant-wide caps that include fugitive dust emissions from roads, compliance with which is going to be based on assumed emission factors, any assumptions for PM emission factors from roads must be tied to specific enforceable measures such as the frequency of road sweeping and/or the quantity and frequency of water or chemical dust suppressant application. As discussed in the attached technical comments, the control efficacy of these types of measures for fugitive dust is based on the frequency of application (as well as the quantity (*i.e*. amount of water or dust suppressant applied per area of road). If the permit or rule is vague – for example, if it requires only the watering of roads "as needed to minimize fugitive dust" – the accuracy of the emission factors used in developing emission caps, and in determining compliance with those caps, is highly questionable and fails to comply with the law.

Response to H-50: UDAQ disagrees with this comment. The commenter attempts to make several points in this comment but the argument can be distilled down to three core ideas:

- A BACT analysis must result in an emission limitation for each emission unit on a pollutant by pollutant basis.
- Plant-wide caps cannot legally represent BACT; and even if they could, UDAQ failed to provide adequate documentation how such caps represent emission unit specific limitations.
- UDAQ did not adequately establish enforceable measures for emission factors used in IX.H to calculate plant-wide caps. For example, the fugitive road dust included in such caps is based on highly questionable assumed emission factors from vague permits or rules.

To properly address UDAQ's development of plant-wide caps on the refineries, a bit of history is required. Although there have been a great number of particulate "SIPs" prepared by UDAQ over the years, there is one of particular note that was last approved by the Utah Air Quality Board (UAQB) in 1991. This SIP was prepared for purposes of addressing the various PM10 nonattainment areas, and has been given various names over the years, but as it was approved by EPA (i.e. published in the federal register) in 1994, let us call it the '94 SIP.

The '94 SIP contained a great number of listed SIP sources, including each of the four refineries still listed today (although three of them were listed under different names at the time). It was also written in a manner similar to that requested by the commenter – a listing of various emission units, each with individual limitations on each of the various pollutants being emitted by that emission unit. At the time UDAQ saw no issue with this approach, since it had also included a provision in the SIP which allowed for updates to the SIP to take place through the regular permitting (NSR/PSD) process. This was later specifically denied by EPA in its approval of the SIP, but no changes were made to the approved SIP. UDAQ also attempted to allow for updates to the SIP through taking those NSR or PSD permits to the UAQB for approval before making them final. This was also disallowed, but no changes were made to the approved SIP. In essence, EPA argued that the SIP process and the permitting process are separate and distinct, and to update the SIP, UDAQ would be required to undertake a SIP change.

UDAQ attempted a number of these over the years which followed, but none were ever approved by EPA. Whether they were never sent as final documents, were withdrawn, were found inadequate or incomplete or otherwise flawed is immaterial, no update to the particulate SIP was ever approved until 2005, when portions of the Utah County section (what now makes up IX.H.3 and IX.H.13) were updated to address highway conformity issues. A period of roughly 21 years had elapsed; and even then, no sources in Salt Lake County were addressed.

In 1995, the Title V Operating Permit program (also known as Part 70) was implemented requiring all sources meeting certain parameters (major sources, major HAP sources, etc) to prepare and submit applications and receive Operating Permits. This included all of the listed SIP sources in Salt Lake County, especially the refineries.

The refinery companies submitted their applications, which included all of the equipment and conditions which applied to their plants as currently configured, but continued to make various changes at their facilities: planned equipment upgrades, plant expansions, new configurations, process changes, etc. – with the end result being that as time passed, the plants no longer resembled the ones listed in the SIP. In at least one case the plant no longer operates any of the equipment listed in the SIP other than some of the storage tanks. The longer the process continued, the more discrepancies between the plants' NSR permits and the '94 SIP became. UDAQ was unable to issue Title V permits as these permits would have contained requirements from the '94 SIP that the sources would have been unable to comply with. Although UDAQ and EPA reached an agreement to delay issuance until the particulate SIP issue could be resolved, eventually both agencies were sued and a solution needed to be found.

Around this same time, UDAQ was in the process of developing the moderate area PM2.5 SIP. Certain historical requirements that applied to all refineries, such as installing and operating 90% efficient SRUs, needed to be retained. Some requirements like testing, monitoring, recordkeeping, and reporting, were the same as those for all other listed SIP sources. Gradually, the development of a "general requirements" section took shape – and all of the common requirements were moved into it to avoid repetition, transcription errors, and to increase commonality and fairness in application.

General refinery minimums were also developed or were brought forward. Some of these were existing items like the previously mentioned SRU requirement. RACM/RACT requirements that could be imposed on all the refineries equally were also added to the general section (IX.H.11.g).
What was left from the original '94 SIP was a SIP Cap, which listed the total emissions for PM10, SO2 and NOx for a subset of the equipment at each refinery – that equipment which had been included in the SIP at the time. UDAQ elected to extend that concept, applying up to date controls where such controls were deemed technologically and economically feasible, and including all emission sources together and making true plant wide caps.

The original SIP Caps had existed in the permits for years, and had always existed for only a subset of the equipment. By extending the concept plant wide, and including the effects of updated controls, substantial emission reductions could be achieved. The innovative approach worked. Several hundred tons of emissions in particulates (PM10 and PM2.5), NOx and SO2 were eliminated, both potential and actual emission decreases occurred, and a new PM10 SIP update was generated which it appears is on track to receive EPA approval.

However, the concept did require that an approach to BACT outside of the traditional permitting concept be employed. Should UDAQ be required to return to the concept of listing individual emission limits on individual emission units as had been the case with the '94 SIP, the process would have likely derailed immediately. The refineries are complex sources that are often making adjustments to equipment or processes based on changing conditions. Markets may require different products, crude feedstocks change – sometimes significantly, new air quality rules (or other agency rules) might require the addition of new equipment or modifications to existing equipment. Over the years since 1994, the listed refineries have, on average, requested roughly three (3) permit changes per year. It has never been the goal of the planning or permitting programs to dictate to sources that they cannot operate as needed or to make changes to their facilities as outside forces might dictate. But when the permitting program cannot issue permits because SIP documents cannot be changed in anything approaching a timely manner (one update between 1994 and 2018 cannot be considered timely), then an innovative approach must be allowed.

The idea of deviating from the NSR/PSD approach is even touched on by EPA and was quoted by the commenter (originally from 81 Fed. Reg. 58081 fn. 160).

…[I]t is reasonable to use the approach adopted in the PSD BACT program as defined in section 169(3) of the Act as an analogue for determining appropriate PM10 nonattainment control measures in serious areas, while at the same time retaining the discretion to depart from that approach on a case-by-case basis as particular circumstances warrant. [emphasis added]

Finally, although the commenter brings up the concept of including a flawed analysis of fugitive road dust emissions into the plant-wide caps, UDAQ is unsure of where the commenter derived this concept. The refinery plant-wide caps do not contain fugitive road dust as monitored emission point. The caps are based on a specific listing of emission units maintained in the NSR permits (AOs) and eventually the Title Vs. This list is not maintained in the SIP for the reasons previously listed – and would not need to be included, as conceptually, a plant-wide cap includes all emission units at the refinery. The caps are based on point source emissions, and not on fugitive emissions that can never be directly measured – hence the reason no VOC cap was created. Total VOC emissions at a refinery are too heavily reliant on estimates of equipment leaks, estimates of tank emissions, off-gassing emissions, and other similar estimated emissions. Basing a plant-wide emission limitation on emission estimates does not provide useful information. Similarly, inclusion of fugitive road-dust (a value likely to be rather insignificant at a fully paved installation like a refinery) in a plant-wide particulate emission cap would provide no additional value.

H-51[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, and Heal Utah]: The Director's BACT Analysis for Fugitive Dust Emissions is Inadequate. *(see Section II. Specific Comments)*

Only if "the director determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results. Utah Admin. Code r.307-401-2.

BACT applies equally to sources of fugitive dust. However, the Director's BACT review for sources of fugitive dust is not legally sufficient. Initially, there is nothing in the record to show that the Director objectively evaluated all the factors outlined in EPA's five-step, top-down method. *Sierra Club*, ¶ 4. fn.2 (citing NRS Manual B.6-9). In addressing fugitive dust, the record does not contain adequate documentation, a list of available technologies, a ranking of controls based on their effectiveness and efficiency and achievable emission rates and reductions or the consideration of their economic or environmental impact. *Id.* The Director's analysis fails to establish that the controls he adopted as BACT for fugitive dust reflect "the maximum degree of emission reduction achievable… considering energy, economic and environmental impacts and other costs." 81 Fed. Reg. at 58081. As a result, there is no record of evidence to show that the Director undertook a defensible BACT analysis that actually represents the most stringent technology and the maximum reduction of emissions achievable. Utah Admin. Code r.307-401-2; *Sierra Club* ¶¶ 4, fn.2, 47-48.

As the legal requirements applicable to Utah's proposed Fugitive Dust Rule, which must be BACM, are likewise applicable to the Director's determination of the BACT necessary to control fugitive dust from sources included in Subpart H, we hereby reference and incorporate the comments we filed addressing the inadequacies of the Fugitive Dust Rule proposed as part of the Provo Nonattainment Area Serious PM2.5 SIP. Those comments, attached hereto, set forth BACM/BACT controls adopted by other states that are BACT for the purposes of Subpart H and therefore that must be adopted by the Director as representing BACT for Utah's serious SIP.

Response to H-51: UDAQ disagrees with this comment. UDAQ performed a BACT analysis for Mining and Fugitive Dust Sources which is found in document DAQ-2018-00716 (Appendix A: BACT for Various Emission Units at Stationary Sources). Section 12 of this document focuses on various mining emission units and fugitive dust activities including crushers, conveyor transfer points and drop points, drilling, explosive blasting, exposed and disturbed areas, hoppers, haul roads, screens, storage piles, and truck loading. The BACT analysis took into consideration all of these fugitive dust activities. The analysis contains a list of control options, technical feasibility, ranking, economic feasibility, and a conclusion or evaluation summary of the control option. Commenter's claim that there is no record of a defensible argument for the fugitive dust BACT analysis is unsupported.

In response to the comment on Utah's Fugitive Dust Rule and it's inadequacies, UDAQ disagrees with the commenter. In reviewing the control measures included as RACM in Utah's Moderate Area PM2.5 SIP, it was determined that in most cases these measures were in fact already stringent enough so as to also meet BACM. UDAQ's review of potential controls entails measures that address primary PM2.5 and precursors to secondary PM2.5, reveals a canvassing of other states, addresses technological and economic feasibility, concludes that the cost benefit in terms of dollars spent per ton of emissions reduced is consistent with contemporary BACT analyses. This is documented in the materials provided as technical support along with Appendix A.

The commenter's contention that Utah has not included every control measure implemented in any other state is more consistent with the idea of Most Stringent Measures (MSM) than BACM. MSM is not required for the Salt Lake area at this time.

H-52[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, and Heal Utah]: All SIP Emission Limits for PM2.5 Must Include Emission Limits for Both Filterable and Condensable PM2.5. *(see Section II. Specific Comments)*

All Subpart H controls on direct emissions of PM2.5 must include emission limits on both filterable and condensable PM2.5. "For sources that are required to adopt a new or revised direct PM2.5 emissions limit as part of the attainment demonstration (including, but not limited to, for RACT, BACT, or MSM), the state must specify PM2.5 emission limits in its SIP that include both filterable and condensable emissions." 81 Fed. Reg. at 58141. "In addition, compliance testing requirements for those sources must include both measurement of filterable and condensable emissions." *Id.* Thus, where the Director has failed to include emission limits, monitoring, recordkeeping and reporting for both filterable and condensable PM2.5, he has failed to comply with the law.

Response to H-52: UDAQ disagrees with the Commenter. The Part H limitations currently list both filterable and condensable PM2.5 limits, monitoring, recordkeeping and reporting where applicable. Compass Minerals has established new emission limits for their facility which contain filterable and condensable limits for PM2.5. Additionally, commenter has failed to provide a list of specific sources which do not address filterable and condensable PM2.5 limits.

H-53[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, and Heal Utah]: The Director has failed to Require Adequate Monitoring for the Purposes of Ensuring Compliance with BACT Emission Limits. *(see Section II. Specific Comments)*

EPA has explained that to meet Clean Air Act requirements, a serious SIP must include adequate monitoring that ensures continuous compliance with any emission limitation or other BACT control. SIP imposed controls must be "enforceable," 42 U.S.C. § 7502(c)(6) ("plan provisions shall include enforceable emission limitations"), and "measurable," and "include periodic source testing, monitoring or other viable means to establish whether the source meets the applicable emission limit." 81 Fed. Reg. at 58133. For an adequate SIP, the "monitoring requirements would have to be sufficient to enable the state or the EPA to determine whether the source is complying with the emission limit on a continuous basis." *Id.* Moreover, because frequent monitoring is a critical element of an emission limit that reflects the maximum emission reduction, the Director must undertake the analysis necessary to show that the frequency of monitoring he proposes reflects BACT.

Frequent monitoring serves to increase the accuracy of emission inventories, to identify appropriate control measures and to reduce emissions. 80 Fed. Reg. 15340, 15453 (March 23, 2015). "[A]ppropriate stationary source emissions monitoring requirements, like the control measures with which they are associated, are a fundamental element of an approvable implementation plan." *Id.* For example, EPA has found that improved monitoring can provide information that allows a source to take "corrective action that could potentially reduce emissions up to 15 percent[.]" *Id.* Similarly, more frequent monitoring "could yield potential stationary source emissions reductions of up to 13 percent." *Id.* Thus, adequate monitoring is a critical component of a SIP intended to ensure that the Salt Lake City serious NAA will meet the 24-hour $PM_{2.5}$ NAAQS as expeditiously as practicable, *see e.g.* 42 U.S.C. § 7513(c)(1) & (c)(2).

In commenting on the 2014 $PM_{2.5}$ SIPs, EPA expressed significant concern about the sufficiency of the infrequent monitoring of $PM_{2.5}$. SIP emission limits. *E.g.* EPA Region 8 Comments on Utah's Proposed $PM_{2.5}$ State Implementation Plans and Technical Support Documents at 7, 9-10 & 12 (Oct. 30, 2014). EPA emphasized that adequate monitoring is a crucial component of an acceptable SIP, *id.* at 12 ("Implementation includes adequate monitoring, which must be in the SIP."), and that stack testing once every three to five years is, on its face, inadequate to show continuous compliance, *id.* at 9-10 ("We are concerned with stack test frequencies longer than one year. Please explain why these test frequencies are sufficient to ensure continuous compliance with the limits."), and requested that the Director explain why the specified monitoring was adequate to support modeling, establish RACT and demonstrate attainment. *Id.* at 7 ("[W]e suggest that UDAQ…clarify and provide more detail…in SIP sections and/or RACT evaluations" to explain "how and why…frequency of monitoring/ testing…(continuous, daily, monthly, etc. for monitoring; once per year, 3 years, 5 years for stack testing)…[is] considered valid to support modeling and attainment").

The Director's current BACT analysis fails address EPA's concerns and to include consideration of the adequacy of the monitoring provisions associated with the particular Subpart H emission limitations. Plainly, where the Director must derive BACT, a more rigorous mandate than RACT, he must do even more to ensure the Subpart H monitoring requirements reflect BACT and ensure continuous compliance. Indeed, in many instances the Director proposes to require stack testing as infrequently as once per every three years and sometimes once every five years. At the same time, he fails to establish how such infrequent stack testing can ensure continuous compliance with the Subpart H emission limitations and so meet the requirements of BACT. As a result, the Director's BACT analysis and Subpart H are not adequate.

Response to H-53: UDAQ agrees with this comment in part. UDAQ has made every effort to increase stack testing frequency where possible and warranted. UDAQ does agree that the once every five year stack test requirement on the FCCUs (see IX.H.11.g.i.B.II) was insufficient, and the remaining version of that requirement was inadvertently included. The condition is being changed to a once every three year stack test; which, when combined with the CPMS monitoring requirement (IX.H.11.g.i.B.III), is sufficient to address EPA's concern that emitting units are operating as designed. Stack testing on many refinery units previously listed as once every three years has also been increased to annually (see the individual monitoring sections in IX.H.12.b, 12.d, 12.g, and 12.m for details).

H-54[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, and Heal Utah]: The Director has failed to Demonstrate Why CEMS Is Not Feasible. *(see Section II. Specific Comments)*

In several instances, the Director has **not** required CEMS to ensure compliance with Subpart H emission limits, although CEMS is a feasible method for monitoring emissions of PM2.5, SOX and NOX. EPA is clear that directly enforceable emission monitoring is preferable wherever feasible. 81 Fed. Reg. at 58133 ("Directly enforceable emission measurements, such as PM CEMS, are preferred wherever feasible."). The Director has failed to show why CEMS is not feasible. After all, CEMS is a critical element of a BACT emission limit and must reflect the maximum degree of emission reductions. Where CEMS has been determined to be feasible in analogous situations and has been applied as BACT, the Director is required to adopt this monitoring requirement or explain why CEMS does not constitute BACT and why alternative monitoring methods are adequate to ensure continuous compliance with the corresponding Subpart H emission limitation.

Response to H-54: UDAQ disagrees with this comment. The installation of CEMs is not always required. Installation of CEMs do not reflect an emission limit, do not reflect the maximum degree of emission reductions, and the commenter has provided no justification for why the Director is required to adopt this monitoring method. Preferred does not equate to must be installed or "required to adopt." Periodic stack testing and/or parametric monitoring is adequate to demonstrate compliance with emission limits, proper operation and maintenance of the control device and demonstration of attainment. Simply requiring installation of CEMs at every emission point is an unnecessary and expensive undertaking that gains little useful data, provides no additional emission reductions (as CEMs are merely a monitoring device and not a control system), and consume environmental agency resources.

H-55[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, and Heal Utah]: The Director Should Consider Applying BACT to U.S. Magnesium. *(see Section II. Specific Comments)*

Because U.S. Magnesium, a major source located just outside and to the west and therefore often upwind of the Salt Lake NAA, emits significant levels of PM2.5, the Director should consider imposing BACT or other emission limits on the source. Under the Clean Air Act, "[a] state has discretion to require reductions from any source inside or outside of a PM2.5 nonattainment area (but within the state's boundaries) in order to fulfill its obligation to demonstrate attainment in a PM2.5 nonattainment area as expeditiously as practicable[.]" 81 Fed. Reg. at 58080. Indeed, if it is necessary to secure emission reductions from U.S. Magnesium in order to show expedited attainment, the Director is required to mandate emission reductions from sources outside the Salt Lake NAA, such as U.S. Magnesium. *Id.* ("A state may need to require emissions reductions on sources located outside of a PM2.5 nonattainment area if such reductions are needed in order to provide for expeditious attainment of the PM2.5 NAAQS.").

Response to H-55: DAQ acknowledges that the Implementation Rule provides authority and direction to control emissions from sources located outside the NAA (but within the state) if necessary to provide for attainment by the attainment date. This authority also extends to PM2.5 plan precursors (those precursors required to be regulated in the applicable attainment plan and/or the NNSR program).
Nevertheless, the applicable attainment plan already demonstrates attainment of the standard by the attainment date. Therefore it is not necessary to extend control beyond the boundary of the nonattainment area.
DAQ remains interested in pursuing some of the questions raised by the Wintertime Fine Particulate Study, among these questions is the attribution of ammonium chloride from U.S. Magnesium. However, it is not compelled by rule to include U.S. Magnesium in the SIP at this time.

H-56[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, Utah Physicians for a Healthy Environment, and Heal Utah]: Comments on Provo Nonattainment Area BACM Analysis *(see June 18 2018 Western Resource Advocates letter)*

Comment 1:
The Director Must Derive and Implement BACM.

Comment 2:
BACM Represents the Maximum Reduction of Emissions Achievable.

Comment 3:
BACM is "Generally Independent" of Attainment.

Comment 4:
BACM Will be More Expensive than RACM.

Comment 5:
BACM for the Provo NAA Is Not Legally Sufficient.

Comment 6:
The Fugitive Emissions Rule is Not BACM.

Comment 7:
Other States Reduce Fugitive Emissions to a Greater Degree and Otherwise Meet the Requirements of BACM.

Comment 8:
The Director Failed to Consider Building Codes as BACM.

Comment 9:
The Director Did Not Consider California's More Stringent Regulations of Non-Road Mobile Sources.

Comment 10:
The Director Did Not Consider California's More Stringent Regulation of On-Road Mobile Sources.

Comment 11:
The Director Can Do More to Address Emissions from Wood Burning.

Response to H-56:
BACM for Provo was made available for public comment from May15 through June16. DAQ responded to those comments it received and submitted them to EPA along with the BACM provisions for Provo.
Comments # 1-4 have been repeated in these comments for the SLC nonattainment area, and are summarized and addressed in H-45.
Comment # 5 is repeated in these comments for the SLC nonattainment area as it would apply to major stationary point sources, the focus of Part H. It is summarized and addressed in H-46.

H-57[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, Utah Physicians for a Healthy Environment, and Heal Utah]: Review of BACT Analyses for Rio Tinto Kennecott Sources *(see I. Technical Report. August 14, 2018)*

The following provides comments on UDAQ's proposed determination of BACT for the Rio Tinto Kennecott Utah Copper (KUC) facilities, as well as on the company's submitted BACT analysis. In general, both UDAQ and KUC failed to provide documentation to verify that the most stringent measures for reducing $PM_{2.5}$ or $PM_{2.5}$ precursor emissions adopted in any SIP or used in practice were considered. Further, KUC failed to rank control technologies from most effective (or lowest achievable emission rate) to least effective.

Response to H-57:

<u>Comment A:</u>
UDAQ and KUC identified fabric filters as the top control technology for direct $PM_{2.5}$ emissions from crushing operations.[6] According to KUC's April 2017 BACT submittal, the in- pit crusher at KUC is already equipped with a baghouse and is subject to a 0.002 grains per dry standard cubic foot (gr/dscf) limit and that it was established by UDAQ as BACT for the BCM in 2011. [7] However, UDAQ's June 2018 BACT analysis states that the KUC crushing operations are currently permitted at 1.77 pounds per hour (lb/hr) and a significantly higher grain loading of 0.016 gr/dscf, eight times higher than the 0.002 gr/dscf limit that KUC claimed applied in its 2017 BACT analysis.[8] A review of a recently issued Approval Order issued for KUC BCM and Copperton Concentrator in January of 2018 does indeed show a PM_{10} limit for the main in-pit crusher baghouse of 1.77 lb/hr and 0.0016 gr/dscf. [9] In any event, UDAQ and KUC proposed a BACT emission limit of 0.002 gr/dscf and UDAQ also proposed a BACT limit of 0.78 lb $PM_{2.5}$ per hour.[10] A review of the Californian Air Resources Board (CARB) BACT Clearinghouse shows lower $PM_{2.5}$ emission limits have been required for similar sources and controls. Specifically, the PM_{10} emission limit at the Rio Rock Materials, Inc. crushing and screening operation is 0.0012 gr/dscf with a baghouse.[11] Indeed, even UDAQ's BACT analysis shows that the KUC BCM crusher's emission rates has been significantly lower than UDAQ's proposed BACT limits. Stack test results at KUC's BCM crusher from 2000 through 2015 show that the highest $PM_{2.5}$ emission rates from the in-pit crusher were measured at 0.164 lb/hr and 0.001 gr/dscf.[12] Thus, there is ample support for a lower $PM_{2.5}$ BACT emission limit on both a lb/hr and a gr/dscf basis at the in-pit crusher. UDAQ should impose lower limits that truly reflect the maximum degree of $PM_{2.5}$ emission reduction that can be achieved with a baghouse at the in-pit crusher. In addition, an opacity limit reflective of BACT must be imposed as a measure to ensure continuous compliance with emission limits and proper operation and maintenance of the baghouse.

Comment A Response:
The commenter stated that UDAQ should impose a lower emission limit for the baghouse at the in-pit crusher. The commenter specifically mentioned the PM_{10} emission level for the Rio Rock Materials, Inc. crushing and screening operation of 0.0012 gr/dscf, listed in the CARB BACT Clearinghouse. This baghouse was permitted in 1993 and had a destruction efficiency of 95.3%. Typically, baghouses have destruction efficiencies starting at 99%. UDAQ could not find any additional information on this source to verify if the BACT determination is accurate and relevant to the in-pit crusher.

The commenter also mentions the stack testing results for the in-pit crusher, which range between 0.01 – 0.164 lb/hr (0.0001 – 0.0031 gr/dscf). As mentioned in the BCM TSD (DAQ-2018-007709), UDAQ's originally proposed a BACT limit of 0.18 lb/hr (0.002 gr/dscf). KUC then provided comments that lowering emissions to 0.18 lb/hr (0.001 gr/dscf per their estimate) is not feasible according to vendor and would require a system modification of $1.56 M/ton. According to KUC "change in bags will not improve performance because of the amount of material we process and the rate we process (truck dump 320 tons at a time). The entire crusher baghouse system would need to be modified in order to determine if improved performance is achievable. Crushed ore loading onto a conveyor belt at the rates we process, creates an up-flow air stream which increases the loading on the bags with heavy particles and impacts its overall performance. Airborne coarse dust from the operations as well as from the surrounding area also impact the performance of the baghouse and overall outlet grain loading." KUC also mentioned significant variation in ore would make it hard to comply with a stricter limit.

KUC initially proposed a limit of 0.30 lb/hr. However, the manufacturer was not able to guarantee this emission rate due to the significant variation in the ore and the air borne coarse dust in the surrounding area. After further evaluation of the initial proposal, KUC proposed a new limit of 0.78 lb/hr. Given the operational variations at the in-pit crusher, UDAQ agreed to the proposed limit of 0.78 lb/hr in Part H to allow for some operational flexibility. UDAQ will also add the 0.007 gr/dscf limit to the proposed limit in Part H in response to EPA Comment H-3.

The commenter also requested that an opacity limitation must be included. The in-pit crusher is subject to an opacity limitation of 7% in Condition II.B.1.c in AO DAQE-AN105710042-18.

No changes were made in response to this comment.

<u>Comment B:</u>
"UDAQ should have evaluated water application PLUS minimizing the drop distance as the most effective control measure for waste rock offloading from trucks. Further, if UDAQ continues to find that minimizing the drop distance satisfies BACT, UDAQ must provide more detail to make this requirement into an enforceable measure. KUC did not even identify or justify as BACT what minimum drop distance should be required to minimize dust emissions from dumping."

Comment B Response:

DAQ determined that water application is not technically feasible because "excessive water application would create geotechnical instability on the waste rock dumps. Additionally, an installation or setup of a water irrigation system for water application is not technically feasible because of the drop location is not static." Therefore, water application was not further evaluated.

The commenter also stated that BACT should specify a drop distance to minimize dust emissions. "Minimizing drop distances" is intended as a work practice standard rather than a numerical limitation. A work practice may be prescribed to satisfy the requirements of BACT, when an emission standard is not feasible (as per the definition of BACT in 40 CFR 52.21(b)(12) and in UAC R307-401-2). Furthermore, it would be difficult to establish a specific drop distance as BACT since emission factors used to estimate emissions from these points are based on material throughput rather than distance. UDAQ was also not able to find other specific drop distance requirements as BACT in EPA RBLC database. A specific drop distance was also not identified as part of the general BACT analysis in Section 12B of Appendix A. Therefore, UDAQ will maintain this requirement as a work practice and will not specify drop distances.

DAQ made no changes in response to this comment.

<u>Comment C:</u>
"Without any discussion or justification, UDAQ and KUC identified the application of water within the pit influence boundary, and water and chemical dust suppressants outside the pit influence boundary, as BACT. UDAQ has not explained why application of water and dust suppressants would not also be BACT for grading operations within the pit influence boundary.

Moreover, neither UDAQ nor KUC identified any specific enforceable requirements that would ensure that the application of water and chemical dust suppressants would permanently reduce $PM_{2.5}$ emissions. For these types of controls, a minimum water application and chemical dust suppressant application frequency and application intensity (quantity per area) must be specified as enforceable measures. EPA has identified the control efficiency of watering to be based on these factors along with the average hourly daytime traffic and the potential average hourly daytime evaporation rate for the area.[18] UDAQ must specify minimum amounts of water application and chemical dust suppressant application as well as identify time between applications as part of its BACT determination, and propose recordkeeping and reporting to ensure compliance."

Comment C Response:

Graders are used primarily to maintain surfaces on haul roads. Bulldozers and front-end loaders are used primarily on the pit, to clean up haul roads, and for dumping operations at the waste rock disposal areas. The application of chemical dust suppressants is not technically feasible for some haul roads and other areas used by these equipment because of the steep grades within the pit and the adverse effect the chemical can have on the coefficient of friction of the road surface. For instance, the grade of haul roads exceeds 10 percent in some locations, creating a slippery skin on the road that inhibits the ability of mobile equipment to brake and steer safely while traveling on the grade. Therefore, DAQ only requires water in the areas within the pit. In areas outside the pit where grades are less extreme, water and chemical dust suppressant are required. This is also mentioned in the BCM TSD (DAQ-2018-007709).

KUC has implemented a comprehensive fugitive dust control plan to minimize emissions from active haul roads. Specifically, the plan requires that BACT measures be implemented, including application of commercial dust suppressants at least twice per year, road base and watering. While the use of watering to the active haul roads is essential to dust mitigation, its application is primarily managed based on weather and operational conditions and conditions "on the ground". This is necessary for the safety of haul truck drivers and other vehicles operating on these roads. KUC has numerous large water trucks that operate continuously and apply water on these roads. Additional trucks are dispatched during dry days as necessary. KUC uses "ground conditions" to determine the frequency of watering in addition to ambient conditions and weather reports. Due to the variation in operational conditions, conditions "on the ground", and weather, DAQ will not specify application frequency and intensity for water or chemical suppressants. The practices outlined in the fugitive dust control plan allow for effective management of dust from the active haul roads.

<u>Comment D:</u>
"…the claimed rapid deterioration of paved haul roads due to the weight of the haul trucks, that is not a justification to eliminate the control method as not technically feasible. Instead, that is an economic factor to be taken into account in the cost effectiveness analysis.[21] Technical infeasibility means that physical, chemical, and engineering principles show that a control technique will not work on the emissions source under review. KUC has not demonstrated that paving of the haul roads is not technically feasible. The company is instead making economic arguments against paving the roads."

"Similarly, while KUC claimed that paving of the roads was not technically feasible due to 'frequently changing road locations,'[22] KUC did not explain in detail how the "changing road locations" made paving not technically feasible. Importantly, how frequent are the haul road changed? Do the road changes affect some parts of the haul roads more than others? Are there more permanent haul roads that could be paved? UDAQ and KUC must provide much more information to claim frequently changing road locations as a reason to exclude the top haul road control technology from the BACM/BACT analysis.

For those haul roads for which it may not be appropriate to require paving and street sweeping, a minimum water application and chemical dust suppressant application frequency and application intensity (quantity per area) must be specified as an enforceable measure. In order to ensure a specific control efficiency, UDAQ must specify minimum amounts of water application and chemical dust suppressant application to unpaved haul roads as well as identify time between applications, and impose recordkeeping and reporting to ensure compliance. It must be noted that UDAQ's proposal to only require twice per year application of chemical dust suppressants to active haul roads outside the pit influence boundary[26] has not been demonstrated by UDAQ to reflect BACT for reducing $PM_{2.5}$ from fugitive dust from these haul roads. Indeed, such an infrequent application of chemical dust suppressant seems wholly inadequate to ensure protection of the 24-hour average $PM_{2.5}$ NAAQS."

In addition, if paving of haul roads is ultimately required as BACT, it is imperative that street sweeping also be required, for which a frequency must be specified as an enforceable control measure. Further, to ensure that watering, application of dust suppressants, and/or street sweeping is adequate to reduce $PM_{2.5}$ emissions to the maximum degree achievable, a concurrent opacity limit is likely necessary for which compliance can be assessed daily or weekly. With that information, KUC can readily determine whether it is time to rewater, or to reapply dust suppressants. Last, it is imperative that recordkeeping and reporting be required as part of the BACM/BACT determination.

Comment D Response:

The commenter stated that paving of haul roads should have been considered as part of the economical feasibility analysis rather than technical feasibility. This option was evaluated as in the technological feasibility analysis because it is difficult to perform an accurate economic analysis for paving the haul roads due to changing mine plans and haul routes.

The commenter stated that UDAQ and KUC must include *"more information to claim frequently changing road locations as a reason to exclude the top haul road control technology from the BACM/BACT analysis*". The commenter went on to list several sources where paving was required as a BACT. Although the commenter mentioned that the weight of trucks was taken into account, it is not clear how the weight of the trucks at the sources listed by the commenter compares to the weight of the trucks at BCM. Furthermore, the sources listed were primarily manufacturing operations, which are not equivalent to the mining operations at the BCM.

The commenter also requested that UDAQ include more specific requirements for water and chemical suppressant application. See the response in H-58 Comment C regarding the application frequencies and requirements of KUC's fugitive dust control plan. The "twice per year application of chemical dust suppressant" is a minimum requirement for active haul roads located outside of the pit influence boundary. The AO requires that active haul roads within the pit influence boundary be treated with road base material, blasted waste rock, crushed rock, or chemical dust suppressant. As stated in response to H-58 Comment C, actual frequency of chemical dust suppressant application varies based on operational conditions, conditions "on the ground", and weather.

Opacity limitations are not included as a Part H limitation, however, such limitations are included in Condition II.B.3.d in AO DAQE-AN105710042-18.

UDAQ made no changes in response to this comment.

<u>Comment E:</u>
KUC's BACT analysis focused primarily on a wintertime control strategy because several nonattainment areas located in the western United States only have experienced exceedances during the winter season.[28] While evaluating seasonal controls may have been acceptable for reasonably available control technology (RACT) under the moderate area SIP requirements, BACT is an emission limitation based on the maximum degree of emission reduction achievable taking into account costs, energy, and non-air quality environmental impacts. 42 U.S.C. §7479(3). Nothing in the definition of BACT or the associated

definition of emission limitation would allow for seasonal controls, despite KUC's claim that the $PM_{2.5}$ nonattainment problem is the worst during the winter season. Indeed, as EPA stated in its August 24, 2016 rulemaking on requirements for the $PM_{2.5}$ NAAQS, "BACM/BACT measures for Serious areas are not solely limited to those measures needed for expeditious attainment...." 81 Fed. Reg. 58,020 (Aug. 24, 2016).

KUC indicated that, as of October 2016, it has permanently ceased operation of Units 1-3 of the Utah Power Plant, and thus a BACT analysis was not conducted for those units.[29] To ensure the validity of excluding these coal- and gas-fired boilers from BACT, these units must no longer be authorized to operate without a determination of and compliance with BACT emission limits.

For the Utah Power Plant Unit 4 boiler, KUC relied on its belief that BACT is only required for the wintertime months. Therefore, it focused its BACT analysis on the months of November 1 to March 1, during which Unit 4 burns natural gas instead the coal that it is allowed to burn for the remaining months of the year. KUC claimed that the Unit 4 is already required under a previous SIP determination to install low NO_x burners with overfire air (LNB with OFA) and selective catalytic reduction (SCR) with 90% control when operating on natural gas during the winter months. Kennecott stated that because the top NO_x technology is already required in previous SIPs, no additional analysis is necessary. [30] For SO_2 BACT, KUC found that burning pipeline quality natural gas, which is already required for the winter months under the previous SIP, is sufficient to meet BACT for SO_2, and that BACT for $PM_{2.5}$ is good combustion practices when burning natural gas, which again is only proposed for the winter months. [31]

UDAQ's proposed BACT determination follows this same approach of focusing on emissions during the winter months. UDAQ did not even evaluate BACT for emissions during the non-winter months when the Unit 4 boiler is authorized to burn coal. Thus, UDAQ's BACT analysis is flawed and incomplete.

There are numerous deficiencies in this BACT analysis for the Unit 4 boiler. First and foremost is the incorrect assumption that BACT under the serious area SIP only applies during the wintertime months, which purportedly is the only time the ambient concentrations exceed the $PM_{2.5}$ NAAQS. There is nothing in the definition of BACT that would support BACT only applying on a seasonal basis, or that BACT is only defined in terms of what is necessary to ensure attainment of the NAAQS. BACT is defined under the Clean Air Act as:

> An emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by- case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each pollutant. In no event, shall application of "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 7411 or 7412 [NSPS or NESHAPs] of this title. . . .

42 U.S.C. §7479(3).[32]

In addition, the Clean Air Act defines an "emissions limitation" and "emissions standard" as:

> A requirement established by the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants *on a continuous basis*, including any requirement relating to the operation and maintenance of a source to assure continuous emission reduction and any design, equipment, work practice or operational standard promulgated under [the Clean Air Act].

42 U.S.C. §7602(k) [emphasis added].[33]

Notably, BACT unlike "reasonably available control technology" or RACT, is not limited by the necessity of imposing such controls to attain and maintain a NAAQS. Further, RACT is not defined as an "emissions limitation" whereas BACT is defined as an "emissions limitation" which therefore means BACT is a requirement limiting emissions on a continuous basis, not on a seasonal basis as needed to attain and maintain the NAAQS. Therefore, BACT for the Unit 4 boiler of the Utah Power Plant must apply on a year-round continuous basis.

In the case of the Unit 4 boiler, the top BACT control technology for $PM_{2.5}$ and the $PM_{2.5}$ precursors of NO_x and SO_2 is pipeline quality gas-firing, with ultra low NO_x burners, overfire air, and SCR operating at no less than 90% NO_x removal efficiency. This suite of fuel and pollution controls will yield the lowest emission rates of all of these pollutants. Since Unit 4 is capable of accommodating natural gas firing 4 months of the year, the unit is clearly capable of firing natural gas year-round. Thus, UDAQ must evaluate a complete switch to natural gas as a BACT option for SO_2, $PM_{2.5}$ and NO_x.

If a complete switch to natural gas is not determined to be BACT and Unit 4 will be allowed to burn coal the remaining 8 months of the year, UDAQ must evaluate BACT for $PM_{2.5}$ and SO_2 when the unit burns coal. An SO_2 scrubber would be the top BACT option for SO_2 emissions from coal-burning, which would ensure the maximum degree of SO_2 emissions reductions the remaining 8 months of the year when Unit 4 can burn coal.[34] For NO_x BACT during the coal-firing months, SCR operated to remove no less than 90% of the NO_x, along with low NO_x burners and overfire air, should form the basis for NO_x BACT at the Unit 4 boiler. Further, UDAQ must also evaluate BACT for $PM_{2.5}$ emissions during coal-firing. With respect to $PM_{2.5}$, the Unit 4 boiler is equipped with an electrostatic precipitator (ESP). BACT controls for direct $PM_{2.5}$ from a coal-fired boiler are typically based on a fabric filter baghouse, which not only provides the best continuous $PM_{2.5}$ control technology, but which also filters out much more of the fine particulate matter than an ESP.

There are numerous examples in the RACT/BACT/LAER Clearinghouse of high efficiency scrubbers for SO_2 BACT, LNB/OFA plus SCR for NO_x BACT, and a fabric filter for $PM_{2.5}$ BACT at coal-fired boilers. Further, these technologies have frequently be retrofitted on coal-fired boilers to meet BACT as well as to meet best available retrofit technology (BART) under the regional haze program.[35] Thus, there is no question that these controls for which the costs were deemed reasonable at other similar sources would be reasonable for the Utah Power Plant Unit 4. However, it will likely be more cost effective for Unit 4 to simply switch to natural gas firing and cease burning coal on a permanent basis. With a switch to natural gas firing the entire year, Unit 4 will not need to install an SO_2 wet scrubber or a fabric filter baghouse for $PM_{2.5}$. Thus, BACT for $PM_{2.5}$ and $PM_{2.5}$ precursors at the Unit 4 boiler should be based on a permanent switch to natural gas and operation of low NO_x burners, OFA, and an SCR system to remove at least 90% of the NO_x emissions.

UDAQ has also not justified its proposed NO_x emission limit for natural gas firing as representative of BACT. KUC initially proposed a NO_x limit of 60 ppmdv (at 3% O_2, 68°F, 29.92 Hg).[36] This equates to a lb/MMBtu NO_x limit of 0.07 lb/MMBtu.[37] According to UDAQ's BACT analysis, KUC subsequently requested a higher NO_x BACT limit of 80 ppm. [38] It is not entirely clear what NO_x limit UDAQ is proposing as BACT for natural gas firing because UDAQ appears to agree with KUC's proposed 80 ppm limit, but UDAQ's proposed revisions to the Utah SIP appear to propose a 20 ppm limit on NO_x. [39] In any event, based on a review of EPA's RACT/BACT/LAER Clearinghouse, the lowest NO_x limit required of a natural gas boiler with low NO_x burners and SCR was a 0.0032 lb/MMBtu NO_x limit required as BACT for two package boilers permitted at the Consolidated Environmental Management Inc.- Nucor Iron Plant in Louisiana (RBLC ID LA-0248, Permit Date 1/27/11). A limit of 0.0032 lb/MMBtu would equate to a NO_x limit of 3 ppmdv (at 3% O_2, 68°F, 29.92 Hg). Thus, UDAQ's and KUC's proposed NO_x BACT limits for the controls of natural gas firing with low NO_x burners, overfire air, and SCR - whether at 80 ppm or 20 ppm - utterly fail to reflect the maximum degree of NO_x emission reduction achievable with such controls. UDAQ must evaluate the top level of NO_x control that is achievable with SCR and low NO_x burners at Unit 4 of the Utah Power Plant in its BACT analysis.

Moreover, UDAQ must impose a BACT limit for ammonia. As UDAQ acknowledged, the SCR system is a source of ammonia due to ammonia slip and ammonia is a precursor to $PM_{2.5}$.40 Ammonia is used as a NO_x reduction agent in an SCR system. Ideally, just the right amount of ammonia is added to fully reduce the amount of NO_x present in the gas stream, but some of the ammonia will pass through as unreacted, which is referred to as "ammonia slip." As stated by UDAQ, the most commonly used approach to address ammonia emissions from SCR is to impose a limit and require monitoring of ammonia slip.41 However, while UDAQ found that this type of limitation is typically in the range of 2.0 to 5.0 ppm and is technically feasible, UDAQ has not proposed such a limit on ammonia slip for Unit 4 because KUC has not provided a cost effectiveness breakdown for the SCR ammonia systems at the [Utah Power Plant] so that a limitation could be established."42 This is not a valid justification for not evaluating and proposing a BACT limit for ammonia. This is a precursor to $PM_{2.5}$ that must be addressed by UDAQ in its BACT determination for the Unit 4 SCR, as well as the Unit 5 SCR.

Comment E Response:
UDAQ has summarized the comment as follows. Each topic will be addressed individually.

- BACT is a requirement limiting emissions on a continuous basis, not on a seasonal basis.
- BACT should be evaluated for coal operations, including SO_2
- BACT should consider a switch to natural gas
- The limits proposed by UDAQ are unclear and do not achieve the maximum emission reduction
- KUC incorrectly stated that no further BACT analysis is required because the top NO_x controlled is already required in previous SIPs
- Units 1-3 should no longer be authorized to operate
- UDAQ must impose BACT for ammonia

<u>Seasonal BACT Determination</u>
UDAQ agrees that BACT is a requirement limiting emissions on a continuous basis, not on a seasonal basis. See Response H-29 to H-34 regarding the DAQ's position on seasonality and BACT.

<u>BACT for Coal Operations</u>
The commenter stated that UDAQ did not evaluate BACT for emissions during the non-winter months when the Unit 4 boiler is authorized to burn coal. The commenter also correctly noted that "*UDAQ must evaluate BACT for $PM_{2.5}$ and SO_2 when the unit burns coal*."

On May 23, 2018, KUC provided a BACT analysis for the coal usage at Unit #4 for the period of March 1 and October 31. This analysis evaluated controls for NO_x and PM emissions. The NO_x controls evaluated were OFA, OFA & SNCR, and OFA & SCR. All control technologies were identified as technologically and economically feasible options. OFA & SCR were identified as the most efficient control technology and was determined as BACT for NO_x on Unit #4. This will reduce emissions from 384 ppm to 80 ppmvd. UDAQ included the BACT limit for coal operations of 80 ppmvd (0.06 lb/MMBtu) in the Part H limit proposed on July 1, 2018.

The May 23, 2018 BACT analysis evaluated electrostatic precipitators (ESPs) and Fabric Filters (FF) as PM controls. Unit 4 is already equipped with an ESP so this unit was not further evaluated. The fabric filter was not found to be economically feasible. No additional PM controls were identified as BACT for Unit #4. The emission rate of ESP for Unit #4 is 0.004 gr/dscf for filterable $PM_{2.5}$ and 0.03 gr/dscf for total $PM_{2.5}$.

As correctly stated by the commenter, KUC and UDAQ did not evaluate BACT for SO_2 as part of the May 23, 2018 submittal or in DAQ-2018-007701. Therefore, UDAQ cannot present an SO_2 limit as part of the Emission Limits and Operating Practices of Section IX, Part H.J.i at this time. UDAQ is requesting the Board to approve an additional public comment period on Part H of the serious $PM_{2.5}$ SIP. UDAQ will work with the source to determine BACT for SO_2. UDAQ expects to complete the analysis and determine BACT prior to the start of the additional comment period, that is expected to begin November 1, 2018.

<u>Switch to Natural Gas</u>

The commenter also stated that a complete switch to natural gas must be evaluated as BACT. UDAQ disagrees with this statement. The purpose of UDAQ's BACT analysis was to evaluate BACT for the proposed operations at a source. UDAQ relied on the sources to define the purpose of operations and equipment design parameters. UDAQ based BACT reviews on the information provided by the source as well as UDAQ's knowledge of operations. As such, three operating scenarios were evaluated as part of BACT: 1) natural gas burning year-round; 2) natural gas burning between November 1 and February 28/29; 3) coal burning between March 1 and October 31. A complete switch to natural gas would redefine operations at this emission unit and was, therefore, not evaluated.

<u>Unclear Limits Proposed by UDAQ</u>

The commenter stated that *"[i]t is not entirely clear what NO_x limit UDAQ is proposing as BACT for natural gas firing because UDAQ appears to agree with KUC's proposed 80 ppm limit, but UDAQ's proposed revisions to the Utah SIP appear to propose a 20 ppm limit on NO_x."*

UDAQ re-evaluated the RACT limits for Unit 4 as part of the BACT analysis for this Serious $PM_{2.5}$ SIP. As part of this BACT review, UDAQ identified that the maximum degree of reduction from an LNB/OFA system is 50% and 90% from an SCR system. UDAQ applied these reduction efficiencies as shown in the table below to derive the 20 ppmvd limit for natural gas operations.

Source	NO_x Emission Rate	Notes
$PM_{2.5}$ Moderate SIP (Part H.12.h.i.D.III) Adopted 2014	336 ppmdv / 60 ppmvd after 1/1/18	Natural Gas, applicable between November 1 to February 28/29
Current NO_x Limit (2015 AO)	336 ppmv / 306 lb/hr	
LNB & OFA	179.2 ppmv / 163.2 lb/hr	50% of current AO limit
SCR + LNB & OFA	17.92 ppmv / 16.32 lb/hr	90% of LNB & OFA emission rate
Part H Limit	20 ppmv / 17 lb/hr	Rounded up values

The 80 ppm limit for NO_x was derived from a BACT analysis provided by KUC on May 23, 2018. The details of this BACT analysis are provided in the previous section of these responses.

The commenter also stated that *"UDAQ's and KUC's proposed NO_x BACT limits for the controls of natural gas firing with low NO_x burners, overfire air, and SCR - whether at 80 ppm or 20 ppm - utterly* *fail to reflect the maximum degree of NO_x emission reduction achievable with such controls."*. Specifically, the commenter also mentioned that lower NO_x limits were identified in EPA's RACT/BACT/LAER Clearinghouse, *"the lowest NO_x limit required of a natural gas boiler with low NO_x burners and SCR was a 0.0032 lb/MMBtu NO_x limit required as BACT for two package boilers permitted at the Consolidated Environmental Management Inc.- Nucor Iron Plant in Louisiana (RBLC ID LA-0248, Permit Date 1/27/11)"*.

DAQ recognizes that there may be other units with more efficient emission rates. UDAQ's analysis based the proposed BACT limits on the uncontrolled emission rate of 336 ppmvd that KUC is currently subject to. UDAQ applied anticipated control efficiencies of each control technology to this uncontrolled emission rate. This was an appropriate approach given the information that was available to UDAQ for this BACT review. BACT is defined as the maximum reduction for each pollutant emitted from any source, on a case-by-case basis. The commenter did not provide any evidence to support the claim that a lower emission rate could be achieved. Specifically, the commenter did not provide any details on how the emission rates for the for two package boilers at the Consolidated Environmental Management Inc.- Nucor Iron Plant in Louisiana could be achieved at Unit #4. UDAQ's proposed limit is appropriate given the information that was available for this unit.

<u>KUC Statement No Further BACT Is Required</u>
See response to H44 Comment 16.

<u>Units 1-3</u>
AO DAQE-AN105710042-18 will be updated to incorporate BACT determinations from this SIP. Units 1-3 will be removed from the AO at that time.

<u>BACT for Ammonia</u>
Ammonia slip from SCRs is a potential source of ammonia emissions. However, the likelihood of being able to identify an exact range is difficult as the SCR unit has not been installed and tested at this time. Therefore, determining an appropriate ammonia slip limitation would not be effective in ensuring compliance and proper source operation as it is new equipment. In order to select a BACT option, UDAQ will review and establish an ammonia slip limit through an Approval Order as well as the Title V Operating Permit.

<u>Comment F:</u>
KUC identified the application of water and chemical dust suppressants, limiting unnecessary traffic, and routine maintenance as BACT for the service roads at the Tailings Site.[43] However, neither UDAQ nor KUC specified enforceable measures to ensure the efficacy of these controls. To ensure that these controls actually reduce $PM_{2.5}$ emissions, a minimum water application frequency and chemical dust suppressant application frequency as well as minimum application intensities (quantity per area) must be specified as an enforceable requirement.

In addition, to ensure that watering, application of dust suppressants, and/or limiting traffic on roads occurs in a manner to ensure $PM_{2.5}$ emission reductions, a concurrent opacity limit is likely necessary for which compliance can be assessed daily or weekly.

Comment F Response:

See the response in H-58 Comment C regarding the application frequencies and requirements of KUC's fugitive dust control plan.

<u>Comment G:</u>

Neither KUC nor UDAQ have proposed any new or upgraded pollution controls as BACT for the smelter. The smelter is a significant source of SO_2 emissions. [45] Kennecott appears to be claiming that because of its unique pollution controls at its copper smelter, it does not need to evaluate whether the copper smelter is equipped with BACT controls or propose emission limits reflective of BACT. While it is true that EPA highlighted the Kennecott Copper Smelter's unique process in the 2002 primary copper smelting MACT rulemaking as a justification for not considering other copper smelters in the same category of the Kennecott copper smelter, that is not justification for not evaluating whether the best available control technology is being utilized at all of the emissions sources associated with the smelter.

For example, there are several scrubbers at the KUC Smelter, but the SO_2 removal efficacy of those scrubbers is not discussed in KUC's BACT analysis and thus it is not known whether the SO_2 removal could be improved by operational changes or scrubber modifications or both. UDAQ must provide more details on the existing controls at the various units of the smelter and the pollutant removal efficiency being achieved by those controls. With that information, a more thorough review of whether the smelter truly is meeting BACT can be made. If the scrubber can be upgraded to improve SO_2 removal efficiencies, UDAQ must conduct such an evaluation of such scrubber upgrades as part of the BACT analysis for the smelter.

Comment G Response:

In response to this comment, UDAQ requested additional information to evaluate BACT for the different processes and control equipment at the smelter. KUC submitted a BACT analysis for different emission units at the smelter on September 10, 2018. The following units were evaluated: anode furnaces, secondary gas system, matte grinding, concentrate dryer, and acid plant. The findings of this BACT analysis are summarized below. Based on the information provided, UDAQ did not make any further BACT recommendations for the smelter.

Anodes Furnaces

In the anodes area, blister copper from the FC furnace is refined in two available refining furnaces to remove the final traces of sulfur. The shaft furnace and holding furnace are used to re-melt anode scrap and other copper scrap to incorporate into copper production. Emissions are vented through baghouses and scrubbers before they are vented to the main stack.

$PM_{2.5}$

KUC uses the most efficient bags available for this process. Most fabric filters are rated at 99.9% control efficiencies. KUC maintains and replaces these bags in accordance with manufacturer recommendations. No additional BACT measures are recommended.

SO_2

KUC uses the scrubbers with removal efficiencies greater than 90% for SO_2. The variability in the offgas SO_2 concentrations and high temperatures of this process can impact the control efficient of the scrubbers. KUC employs standard operating procedures, work practices, and maintenance procedures recommended by the manufacturer, to optimize the control efficiency of the scrubbers. No additional BACT measures are recommended.

NO_x

KUC evaluated the following NO_x controls: oxy-fuel burners, SCR, low temperature SCR, low temperature oxidation system, wet scrubber. All control options are technologically feasible. The anode area furnaces are already equipped with oxy-fuel burners, which have an actual emission rate of approximately 30 ppm. Additional controls, such as SCRs or wet scrubbers, were not determined to be economically feasible. No additional BACT measures are recommended.

Secondary Gas System

The secondary gas system collects fugitive emissions in the hot metals building (typically associated with the furnaces) and vents them through a baghouse and a sodium-based scrubber before they are vented to the main stack.

$PM_{2.5}$

KUC uses the most efficient bags available for this process. Most fabric filters are rated at 99.9% control efficiencies. KUC maintains and replaces these bags in accordance with manufacturer recommendations. No additional BACT measures are recommended.

SO_2

KUC uses the scrubbers with removal efficiencies greater than 90% for SO_2. The variability in the offgas SO_2 concentrations and high temperatures of this process can impact the control efficient of the scrubbers. KUC employs standard operating procedures, work practices, and maintenance procedures recommended by the manufacturer, to optimize the control efficiency of the scrubbers. No additional BACT measures are recommended.

Matte Grinding

The matte grinding circuit crushes and dries granulated matte for use in the FC furnace. The particulate from the ground matte is collected in a baghouse.

$PM_{2.5}$

KUC uses the most efficient bags available for this process. Most fabric filters are rated at 99.9% control efficiencies. KUC maintains and replaces these bags in accordance with manufacturer recommendations. No additional BACT measures are recommended.

Concentrate Dryer

The concentrate dryer heats/dries the concentrate for use in the FC furnace. Emissions from the process are vented through a baghouse and a sodium-based scrubber before they are exhausted to the main stack.

$PM_{2.5}$

KUC uses the most efficient bags available for this process. Most fabric filters are rated at 99.9% control efficiencies. KUC maintains and replaces these bags in accordance with manufacturer recommendations. No additional BACT measures are recommended.

SO_2

KUC uses the scrubbers with removal efficiencies greater than 90% for SO_2. The variability in the offgas SO_2 concentrations and high temperatures of this process can impact the control efficient of the scrubbers. KUC employs standard operating procedures, work practices, and maintenance procedures recommended by the manufacturer, to optimize the control efficiency of the scrubbers. No additional BACT measures are recommended.

Acid Plant

Double contact acid plants (DCAPs) continue to be the state of the art technology for sulfuric acid plants because they implement two absorption stages for increased conversion efficiency. SO_2 emissions are generated from unconverted gases.

DCAPs for metallurgical applications have the potential to operate less efficiently because SO_2 concentrations produced from smelting activities can demonstrate a high level of variability both due to the smelting process and the sulfur content in the feed. Implementing the flash smelting and flash converting technologies as well as treating the offgas has allowed KUC to see lower SO_2 emissions than other copper smelters. However, the variability in SO_2 concentrations from the smelting process creates additional challenges for achieving DCAP conversion efficiencies compared to a typical sulfuric acid production facility with a steady source. For this reason, KUC has implemented the maintenance procedures recommended by the manufacturer, as well as developed several standard operating procedures and work practices specific to operating the DCAP for the copper smelting process. Aside from implementing the developed work practices, KUC is unaware of any additional upgrades to the DCAP that would improve overall operational efficiency.

No additional BACT measures are recommended.

H-58[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, Utah Physicians for a Healthy Environment, and Heal Utah]: Review of BACT Analyses for the Petroleum Refineries.
(see II. Technical Report. August 14, 2018)

Response to H-58: There are four oil refineries in the Salt Lake and Provo Serious ozone **[sic]** nonattainment areas: Chevron, Tesoro, Holly Frontier, and Big West. With a few exceptions, neither UDAQ nor the refinery owners have proposed any additional pollution controls or requirements to meet BACT at most of the emission units at these refineries. However, the companies' justifications for not adding new pollution controls to meet BACT are often not adequately justified. UDAQ generally has seemed to accept what has been proposed as BACT by the refineries at face value, without ensuring consistency in emissions assumptions and cost effectiveness analyses for similar controls at the four refineries. UDAQ must evaluate and implement BACT for the refineries consistently. Moreover, in some cases, UDAQ has not imposed as restrictive emission limits as proposed by the refinery owner in its BACT analysis. These details are provided below.

Comment A:
SO2 BACT for Heaters, Boilers, and Other Process Units that Utilize Refinery Fuel Gas.

Comment A Response: UDAQ disagrees with this comment. The commenter mentions several options that it claims should have been considered by UDAQ in UDAQ's BACT analysis, but does so without pointing out any of the inherent flaws with those options. Each option is discussed below.

- The Arizona Clean Fuels Yuma Petroleum Refinery: Two different options are discussed from this "recently" issued PSD permit, having a reserve storage of amine (up to 24-hours) to use in case of upset conditions, and improvements in sulfur conversion to lower the fuel gas H2S content from 60 ppm to 35 ppm annually.
    1. The commenter fails to mention that although the permit was issued in 2006, the refinery has never been built. The website for the refinery appears to be permanently down for maintenance.
    2. As the refinery has never been built, the permit limit has not been demonstrated in practice, and cannot be relied on for establishment of a SIP BACT limitation.
    3. The commenter claims that the largest expense for the project would be building tanks for the storage of rich amine, although efficiency improvements in sulfur conversion would necessitate at least some level of redesign and reconstruction of the SRU – a far more costly and time intensive undertaking.

- Flint Hills Resources Pine Bend Refinery: Switching amine species from MEA to DGA to more efficiently remove sulfur and lower steam requirements.
    1. There are many different types of amine species: MEA – monoethanolamine, DEA – diethanolamine, MDEA – methyl diethanolamine, DGA – diglycolamine, being the most common although there are multiple others. All of the Salt Lake NAA refineries use MDEA. MDEA is considered an advanced amine with a lower vapor pressure than MEA and a higher selectivity for H2S capture and would be considered the best selection for amine technology for the local refineries. MDEA is a tertiary amine with high H2S removal properties. MEA is a primary amine with a higher vapor pressure and lower H2S selectivity. DGA is a secondary amine and is less selective than MDEA in H2S removal. It is also a proprietary product produced by Huntsman Chemical Co., and would require additional licensing. UDAQ did not investigate switching amine species, as each of the refineries was already using an advanced tertiary amine and little to no benefit would be gained by converting to an alternative species.
- Installation of a polishing amine or caustic scrubber: The primary claim here is UDAQ's acceptance of Tesoro's argument that installation of such a system is not technically feasible based on the date of December 31, 2018. The commenter instead bases the claim that BACM (including BACT) is those controls that can be implemented in whole or in part within four years after the date of reclassification to serious. Since the date of reclassification was May 10, 2017 the date for BACM/BACT should therefore be May 10, 2021.
    1. The commenter is incorrect in its analysis. While it references the first part of the rule correctly, it fails to take into account that the regulatory attainment date is December 31, 2019. Obviously, no credit can be taken for any BACM or more specifically BACT which is installed after the attainment date. An area is either in attainment on that date or it is not. Should the state choose to extend the attainment date, then this argument could be raised. More specifically, this is listed in the rule under the requirements for attainment demonstration for nonattainment areas reclassified as Serious – see 40 CFR 41.1011(b)(5):

       Required timeframe for obtaining emissions reductions. For each Serious nonattainment area, the attainment plan must provide for implementation of all control measures needed for attainment as expeditiously as practicable. All control measures must be implemented no later than the beginning of the year containing the applicable attainment date, notwithstanding BACM implementation deadline requirements in § 51.1010.

       Thus, for any BACM/BACT to be included for emission reductions, it must be implemented no later than the beginning of the year containing the regulatory attainment date, i.e. on or before January 1, 2019. In order for a control system to be in operation by January 1, 2019, it must be constructed no later than December 31, 2018. While it is true that UDAQ did not provide additional detail regarding the planning, permitting, construction and eventual operation of a new control device, past experience does allow UDAQ to make this determination.
- Meridian Davis refinery: The commenter claims that UDAQ should have considered Merichem's LO-CAT technology for sulfur recovery.
    1. Again, this is technology mentioned in the application for a proposed refinery that is not yet under construction, much less operation. Although groundbreaking was held in July of 2018, the permit for the facility was issued under the assumption that the initial phase would already be complete with the full refinery in operation in 2019. As with the Yuma facility mentioned above, emission limits established only in permits and not yet demonstrated in practice cannot be used as the basis for establishing SIP BACT.
    2. Although the commenter includes superlatives like 100% turndown in gas flow and 99.9% removal efficiency in H2S, these values come directly from the application.
    3. The permit for this facility was only finalized on June 12, 2018, approximately the same date as the completion of the technical support documentation for the SIP. UDAQ believes it is

unreasonable to assume that it could base its analysis on information that would only have been available at best for a period of less than two weeks.

- Use of NSPS Subpart Ja limits as final rather than as a starting “floor”: The commenter claims that the various refineries submitted no additional information beyond each of their existing controls, and that UDAQ simply agreed that since each refinery was meeting the Subpart Ja requirements for fuel gas, these controls were sufficient to meet BACT.
    1. While this has been addressed elsewhere (see above Comments H-6 and H-47) in part, the commenter is incorrect. It appears as though the commenter based its comments on the refineries’ initial BACT review submittals, and not on the full set of documentation for each source. For example, in the second submittal for Chevron, which was received by UDAQ on March 23, 2018, Chevron included additional information describing the actual emissions for all fuel burning equipment at the refinery. Total SO2 emissions from all refinery fuel gas combustion (which discounts the two SRUs, the FCC regenerator, flaring emissions, and items such as diesel-fired emergency engines) were just 0.39 tons per year in 2017. Less than one ton for all boilers, heaters and furnaces combined. Potential emissions are set higher to allow for flexibility and process variations, but emission values remain small. Similarly, in Big West Oil’s Amended BACT Evaluation (received February 1, 2018) the use of wet gas scrubbing was evaluated for and determined to be both technically and economically infeasible – technically due to a lack of space for locating the control system given the flue gas discharge constraints, and economically with an estimated control cost of approximately $2.0 million per ton of pollutant removed for the most cost effective combination of specific emitting unit (heaters >40MMBtu/hr) and total pollutants (SO2+NOx+particulate) removed.
    2. Although lower emission limits are possible when applied to an individual refinery, the emission limits appearing in section IX.H.11.g.ii for refinery fuel gas represent the minimums that any refinery located within, or affecting any PM2.5 nonattainment area (or seeking to do so in the future) must meet – even prior to the application of BACT. The wording that appears in the technical support documentation prepared by UDAQ is unfortunate in that it seems to imply that this represents the maximum required. Rather it is meant to imply that the source’s selection of BACT meets the minimum requirement and is acceptable to UDAQ. As is explained elsewhere in this response to comments, UDAQ used an alternate approach to setting BACT emission limits for certain complex sources.

<u>Comment B:</u>
NOx BACT for Refinery Process Heaters and Boilers.

Comment B Response: UDAQ disagrees with this comment. While the commenter once again provided many specific examples of supposed shortcomings or failings with UDAQ’s BACT review, these examples were similar to the arguments that had been provided previously in the SO2 BACT discussion – and were similarly flawed. The commenter cited from the same proposed, but not yet constructed, refineries; referencing limitations from those permits that have not been demonstrated in practice; incorrectly representing the time period for BACT applicability; and failing to review the complete and up-to-date BACT analysis submissions from the refineries. Specific examples follow.

- The Arizona Clean Fuels Yuma Petroleum Refinery: The commenter states that a combination of ultra-low NOx burners (ULNB) plus SCR was proposed and required as BACT at a cost effectiveness of $23,000 per ton.
    1. Again, the commenter fails to mention that the refinery has never been built, and thus the final cost analysis cannot be determined. In addition, the cost analysis determination was made in 2006 (the time of permitting) and is therefore over a decade old.

2. The cost effectiveness was performed only for large boilers over 100 MMBtu/hr. The majority of heaters and boilers at four listed Salt Lake refineries are between 40 MMBtu/hr and 100 MMBtu/hr.
3. When listing cost effectiveness comparisons, the commenter provides Chevron's initial cost analysis (from the May 1, 2017 BACT analysis submission) of approximately $75,000 to $120,000 per ton of NOx removed, but fails to mention the point of the inclusion. Does it consider this value economically feasible? Infeasible? Does it disagree with Chevron's calculations?
   When reviewing Chevron's updated submission from March 28, 2018, UDAQ points out that installation of ULNB and SCR each have much lower cost effectiveness values ranging from approximately $10,000 to $50,000 per ton for ULNB and $25,000 to $52,000 per ton for SCR, depending on the emission unit. However, technical feasibility concerns are still an issue.

- The claim of technical infeasibility based on an installation date of December 31, 2018: The commenter bases the claim that BACM (including BACT) are those controls that can be implemented in whole or in part within four years after the date of reclassification to serious. Since the date of reclassification was May 10, 2017 the date for BACM/BACT should therefore be May 10, 2021.
  1. As mentioned above in the SO2 response, the commenter is incorrect in its analysis. The comment fails to take into account that the regulatory attainment date is December 31, 2019. This is listed in the rule under the requirements for attainment demonstration for nonattainment areas reclassified as Serious – see 40 CFR 51.1011(b)(5). Thus, for any BACM/BACT to be included for emission reductions, it must be implemented no later than the beginning of the year containing the regulatory attainment date, i.e. on or before December 31, 2018. See the SO2 response above for additional details.
- The commenter's methodology for determining BACT is incorrect, based on facts not in evidence, and overly aggressive.
  1. The commenter claims a 25-year life is more appropriate for a SCR and cites only a single reference to back up this claim, specifically EPA's Control Cost Manual. In UDAQ's review of that document, from both the most recent version (Sixth Edition, January 2002) and the unfinished updates (Seventh Edition, November 2017)[2,3] give a value of 20 years as appropriate for industrial boilers. Although a range of 20-25 years is given in the Seventh edition updates, nowhere does it state that 25-years is more appropriate, or that the highest value of the range must be used. Should a source wish to use a more conservative length of life for a control device, this is still acceptable.
  2. Interest rates are highly variable and subject to change. The 2002 version of the manual suggests using an interest rate of 7%, but this interest rate is not set in stone. The 2017 update suggests using a rate of 4.25%, but the manual clearly states this is based on data collected from 2012 – when the prime lending rate was still extremely low (0-0.25%). The current prime rate has risen nearly 2 percentage points and is expected to continue climbing. Using a value other than 7% is not unreasonable. Especially given that the end result of the analysis does not eliminate either ULNB or SCR based on economic feasibility.
  3. The comment assumed that Chevron's baseline emissions from 2015 were not reflective of normal operations or that these emissions were somehow abnormally low: UDAQ reviewed these emissions based on both the 2014 and 2016 emission inventories and saw no abnormalities.

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[2] EPA Control Cost Manual, Sixth Edition, January 2002, available at: https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf, see Section 1, Chapter 2 – Estimating Costs, and Section 4.2, Chapter 2 Selective Catalytic Reduction

[3] EPA Control Cost Manual, Seventh Edition Update, November 2017, available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution, see Section 1, Chapter 2 – Estimating Costs, and Section 4 NOx Controls, Chapter 2 - Selective Catalytic Reduction

4. Although Chevron's plans to decommission three boilers (boilers #1, #2 and #4) and add a new boiler (boiler #7) have already been permitted and work begun on this process (Approval Order DAQE-AN101190094-16, issued 11/16/2016), the commenter implies that emission increases from boilers #5 and #6 will likely occur and that this was not taken into account. In reality, new boiler #7 (for which the anticipated emissions were included in the BACT review) will allow Chevron to decrease actual NOx emissions by approximately 120 tons per year.
5. Claims that SCR can achieve 95% or better control efficiency: UDAQ agrees that this is possible for properly designed SCR systems being installed on new boiler configurations as part of the original engineering design – i.e. installed as a single package. When added on to an existing boiler configuration with unknown flue gas flows, variable heating processes, unknown temperature profiles, estimated emission contaminants and estimated stack parameters – retrofitted control systems rarely perform as well as initial installations.
6. The commenter claims that the Holly refinery's installation of SCR automatically makes SCR cost-effective. While it certainly lends weight of evidence, Holly may simply have chosen to install SCR for reasons other than purely economic ones. Other sources are then evaluated on a case-by-case basis, taking the installation at Holly into account as one consideration.

   Given that the commenter did not review the more recent updated BACT analysis submittals from the refineries (Tesoro, dated December 11, 2017; BWO, dated February 1, 2018; Chevron, dated March 28, 2018), it failed to notice the updated economic analyses performed by the sources, including cost data and more detailed technical analyses. These documents were included in UDAQ's BACT review as can be seen in the References associated with each Technical Support Document.

<u>Comment C:</u>
BACT for the Fluidized Catalytic Cracking Units (FCCUs).

Comment C Response: For the FCCUs, the comment focused entirely on the installation of a wet gas scrubbing (WGS) unit in combination with Lo-TOx. This is the chosen control technology for both the Tesoro and Holly refineries, although each refinery proposed different final emission values for various pollutants. The Chevron and Big West (BWO) refineries proposed alternative control methodologies based on existing control systems already in place. The full text of the comment is not reproduced here, but the arguments boil down to the following:

- Tesoro proposed the lowest emission values, but these emission values are not listed as specific emission limitations in the SIP
- Holly proposed higher emission limits and should be held to the same values as Tesoro
- Chevron evaluated the installation of WGS+LoTOx incorrectly and should be held to the same limits as Tesoro
- BWO evaluated the installation of WGS+LoTOx incorrectly and should be held to the same limits as Tesoro
- All of the emission limits should be listed in the SIP

The discussion as to UDAQ's approach to emission limitations on individual emission units for the refineries has been discussed elsewhere. Please see UDAQ's response to Comment H-50 for details.

Tesoro proposed a WGS to control SO2 emissions from the FCCU. Tesoro's existing FCCU remains equipped with an ESP for primary particulate control, as Tesoro did not anticipate any particulate control from the WGS during engineering, design and installation. Although some degree of particulate control was expected, Tesoro did not account for, nor take credit for, any particulate emission reduction from installation of the WGS. This is most clearly demonstrated on the emission spreadsheets prepared by

UDAQ for use in the SIP attainment demonstration model. Line 293, Column AN, shows the projected effect of installation of the WGS on the projected emissions for emission year 2019 – and reflects no change. Tesoro's primary focus was the control of SO2 emissions from the refinery, which it expected to attain through the application of the WGS on the FCCU and tail gas treatment on the SRU. The WGS was designed primarily just for SO2 control, with the installation of Lo-TOx to control NOx emissions. Inlet particulate emissions were expected to be low since an ESP was already being employed for particulate control.

Holly installed two WGS units which function differently from Tesoro's WGS. Both units are installed to control emissions from two different sources – a FCCU and the SRU. Holly operates two FCCUs and one SRU equipped with a tail gas incinerator (TGI), each WGS controls one of the FCCUs, with WGS #1 primarily controlling the emissions from the TGI, although WGS #2 can also be used in the event that WGS #1 is offline for maintenance or is at capacity. Holly's primary WGS was installed as part of a consent decree; while WGS #2 was included as part of its refinery expansion in 2016 and proposed as RACT/BACT level controls during development of the moderate PM2.5 nonattainment area SIP (see UDAQ's response to Comment H-46 for details on Beyond RACT Controls). Because it was designed to control emissions from both the FCCU and the SRU, higher inlet particulate loading was expected – Holly does not have primary particulate removal on the FCCUs like Tesoro. The species and source of sulfur emissions is variable in Holly's case, since both a FCCU and SRU/TGI produce sulfur related emissions. NOx emissions are expected to be higher in Holly's case, since the TGI is a thermal incineration device for oxidizing any remaining H2S to SO2 prior to release to the atmosphere.

There are some fundamental differences between the two systems that make setting the emission limits equal between the two sources problematic. Holly's initial WGS was installed and operational in 2012, six full years before Tesoro's system was fully installed. It is to be expected that a newer system would have slightly improved emission controls. Holly did not provide a cost analysis for upgrading the WGS to match Tesoro's expected emission values for NOx and SO2, but upgrades in emission capture, ozone injection, scrubber liquor flow, pressure drop maintenance (larger fan flow), duct work improvements, higher energy costs, solid and liquid waste disposal, and other costs would likely render such an improvement economically infeasible. It is also highly probable that such changes could not be implemented prior to January 1, 2019, and thus are technically infeasible as well.

The discussion on NSPS limits representing BACT has also been addressed elsewhere, see UDAQ's response to Comment H-47 for details, and will not be covered here.

BWO made several claims regarding infeasibility. Economically, the installation of WGS was eliminated with a cost effectiveness of $20 million/ton of pollutant removed. Although space considerations alone are not a compelling reason for technical infeasibility, BWO did supply UDAQ with images showing how the existing FCCU at the refinery is completely surrounded by other equipment. UDAQ investigated alternate WGS units such as that Exxon/Mobil unit mentioned by the commenter and determined that even if such a unit could be retrofitted into the existing space or configuration allowed by BWO's other equipment – the additional engineering required for stack parameter adjustments (stack gas cooling, plume rise, dew point considerations, scrubbing liquor flow, ozone generation equipment placement) and other concerns would not be completed prior to the regulatory attainment date of 12/31/2019, let alone the required BACT installation date of 12/31/2018. Thus the use of WGS is not technically justified for BWO.

The commenter based its analysis on Chevron's initial BACT analysis, and not on the most recent March 28, 2018 submittal, which discussed Chevron's use of feed hydrotreating in great detail. Rather than relying on post-processing emission controls, such as WGS and Lo-TOx, Chevron instead uses hydrotreating – or the injection of hydrogen into the hot feedstock to pretreat the process and eliminate the need for post-process controls. Sulfur emissions drop significantly since it is removed in an amine contact process prior to possible combustion in the FCCU. Chevron's more recent submission discussed economic infeasibility in more detail than was provided in the original 2017 submission. Although the commenter is correct that Chevron did not provide an analysis of the cost effectiveness for all three pollutants combined, but such calculation can be easily performed: Total emission reduction is 24.5 tons of PM2.5 + 0 tons of SO2 (no additional reduction over feed hydrotreating) + 22.7 tons of NOx = 47.2 tons of pollutants. Total annual costs = $1,943,322 for WGS+LoTOx (see pages 4, 7, 11 of the Chevron March 28, 2018 BACT Submission). Cost effectiveness = $41,172 per ton of pollutant removed. While this value of cost effectiveness is potentially economically feasible, WGS is still not considered BACT. The choice of BACT is not simply one of, "this system achieves lower emissions," or, "this system is obviously affordable." Rather, when viewed in context with the limited amount of time for design and construction, and the limited additional benefit obtained over Chevron's existing control system, the additional cost for WGS is not justified.

<u>Comment D:</u>
BACT for Flaring.

Comment D Response: The comment on flaring operations was that UDAQ only included the NSPS Subpart Ja requirements and a design limit on the quantity of gases flared per year. The commenter feels that including the refinery MACT standards on flaring from 40 CFR 63.670 and 63.671 would also serve as BACT. UDAQ disagrees with this comment. Firstly, the limitation on the quantity of gases that can be flared is on a daily basis (see proposed requirements: IX.H.11.g.v.A and IX.H.11.g.v.B) – alternatively the source can also install a flare gas recovery system. Secondly, the sections of the federal MACT standards cited by the commenter are a subset of 40 CFR 63 Subpart CC National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries. All of the listed refineries are already subject to the requirements of Subpart CC as major sources of HAPs, and thus including these requirements would be redundant.

However, at the time of preparation of the original Moderate PM2.5 nonattainment area SIP the listed refineries were not categorically subject to the provisions of 40 CFR 60 Subpart Ja – including the flaring requirements. During development of the RACM/BACM controls for the moderate SIP, one of the control techniques was making all hydrocarbon flares subject to the flare requirements of Subpart Ja, and including either a flare gas recovery system or limit on total flaring during normal operations. As these controls were determined at that time to be both RACM and BACM, they were simply re-reviewed during development of the serious SIP. However, there is no need to specifically include the MACT CC requirements the sources are already obligated to meet.

H-59[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, Utah Physicians for a Healthy Environment, and Heal Utah]: Review of BACT Analyses for the West Valley Power Plant *(see III. Technical Report. August 14, 2018)*

<u>General Comments:</u>

General Comment Responses:

The commenter submitted a number of combined comments on the West Valley Power Plant (WVPP). Although the full text of the comment is not reproduced here, in summary the comments are as follows:

- The WVPP used an incorrect starting point in its BACT analysis,
- The cost analysis was flawed as existing controls should not have been taken into account,
- The analysis was based on an improper calculation of average emission rate,

- The WVPP used a historically low estimate of hours of operation thus artificially lowering estimated emissions,
- The WVPP was selective in choosing vendors, cost estimates and other vendor provided data to artificially weigh the analysis.

Response to H-59: UDAQ disagrees with these comments. The commenter makes several errors in its review of the WVPP analysis:

1. The commenter claimed that WVPP was in error when stating that the lowest emission rate for NOx for simple cycle turbines was 2.5 ppm on a 1-hr average basis. It claimed to have found a lower emission rate of 2.0 ppm for a California facility in the RBLC. UDAQ has reviewed the RBLC entry for this plant, and performed additional follow-up review work and determined that the permit was issued for an expansion to an existing facility (not a greenfield site as claimed on the RBLC). The plant is a 1,000 MW combined cycle facility, using Frame 7FA turbines which are much larger and of a different fundamental design than the simple cycle LM6000 turbines at the WVPP.
    a. A further review of the RBLC, searching only for simple cycle turbines revealed no other simple cycle turbines with an emission limit lower than 2.5 ppm regardless of averaging period. Although the RBLC is not the most comprehensive list of BACT determinations, UDAQ has been unable to find lower emission values for turbines with similar power output ratings.
2. The commenter claims that a BACT analysis is based on “essentially uncontrolled emissions, calculated using a ‘realistic scenario of upper boundary uncontrolled emissions.’” This quote is taken from the October 1990 New Source Review Workshop Manual (page B-37). However, this is not at all what this quote is referring to. The quote is taken from a section of the manual referring to the calculation of baseline emissions. Baseline emissions are important when calculating one form of cost effectiveness referred to in that same manual as “average cost effectiveness” (see section IV.D.2.b Cost Effectiveness, page B-36). However, as that same section of the manual explains, there are two measures for calculating cost effectiveness: average, and incremental cost effectiveness.
    a. Incremental cost effectiveness is explained later in that same section of the manual, and is used when comparing two dominate control options. It is also useful when comparing a single control option over a range of control efficiencies (*Id.* at B-43) – such as comparing SCR controls between 2.5 ppm and 2.0 ppm.
3. In determining average emission rate, the commenter is mistaken on how average emissions are determined for SIP listed sources. Rather than choosing a period of emissions representative of high or low emissions within a particular baseline period; such as is the case for making a modification under the NSR or PSD permitting rules. Each source’s baseline emissions were set as of the baseline inventory year, in this case 2014. The baseline year was later moved to 2016, but the emissions were brought forward by UDAQ using the 2014 inventory submissions. In other words, each source was required to base its BACT analysis on potential additional emission reductions from the actual 2014 emissions. And those 2014 actual emissions would have obviously been post-existing-controls – not based on some arbitrary and hypothetical uncontrolled set of emissions from some maximum rate of operation.
4. UDAQ is unsure what point the commenter is raising about vendor supplied information, other than the WVPP erred on the side of caution in selecting higher vendor cost estimates and an unwillingness to experiment with testing existing controls to see if lower emissions were possible. The current owner only recently purchased the WVPP within the last 18-24 months, and while the existing operating personnel were retained, a degree of caution with an expensive capital investment seems reasonable. UDAQ also disagrees with the commenters’ analysis of anticipated lifetime of SCR catalyst. While the manufacturer supplied expected life of 30,000 hours would imply a 40-60 year lifetime if the unit is only operated 500-700 hours per year – various factors

come into play to lower or reduce that expected lifetime. Rapid and/or repeated heating/cooling, poisoning of the catalyst, physical damage, operation outside of recommended operating ranges, even long periods of inactivity can all contribute to reducing the overall expected life. A more common analogy is the 5-year lightbulb – which may last five years if operated continuously, but which burns out in a few months if turned on and off many times a day.

H-60[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, Utah Physicians for a Healthy Environment, and Heal Utah]: Review of BACT Analyses for Gadsby Power Plant *(see IV. Technical Report. August 14, 2018)*

The commenter provides much the same argument for the Gadsby combustion turbines (Units #4, #5 and #6) as it made on the WVPP (see Comment H-60 above). Specifically:

- that PacifiCorp's claim that the lowest emission rate of 2.5 ppm NOx limit on a 1-hour basis was incorrect,
- that PacifiCorp should have conducted a more thorough analysis resulting in a 2.0 ppm NOx limit,
- that PacifiCorp did not perform a proper cost analysis
- that UDAQ accepted the PacifiCorp analysis without question.

Response to H-60: UDAQ disagrees with this comment. As with the WVPP comment (see UDAQ's response to H-59 above), the commenter is wrong on a number of points. The lowest emission rate for a simple cycle combustion turbine in the RBLC is 2.5 ppm NOx on a 1-hour average basis. The value quoted by the commenter is for a combined cycle turbine, using a different base model (frame 7FA versus LM6000, rated at approximately 2-3 times the power output.

UDAQ did perform a review of other states (CA, NJ, AZ, TX, AK, ND) as well as the RBLC looking for simple cycle gas turbines with lower emission rates and did not find any below 2.5 ppm. UDAQ concluded that PacifCorp's analysis was sound and could find no reason to disagree with its conclusions. UDAQ did suggest that an emission rate of 2.5 ppm should be imposed as AFM/MSM if required, but that no additional controls would be required at the existing emission levels and attainment date.

H-61[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, Utah Physicians for a Healthy Environment and Heal Utah]: Review of BACT Analyses for Lhoist North America – Grantsville Facility *(see V. Technical Report. August 14, 2018)*

The Lhoist North American quarry and lime processing plant, which began operations in 1960, includes the following emitting activities: mining, limestone processing, one rotary kiln which heats crushed limestone and converts it to quicklime or calcium oxide, post-kiln lime processing, lime hydration equipment to convert quicklime to hydrated lime (calcium hydroxide), bagging facilities, and loadout facilities. According to the company's BACT analysis, the lime manufacturing operations of this facility have essentially been suspended since 2008, although purportedly the plant is being maintained to remain in complete "ready mode."

Response to H-61: Comments 1 – 7:

Comment 1: Given that this plant has not been operating for close to 10 years, UDAQ should simply revoke the facility's operating permit. The Lhoist North American facility could not resume operation after being shut down for 10 years or more without being subject to major new source review (NSR) permitting requirements, which for PM2.5 and PM2.5 precursor emissions would require that the lowest achievable emission rate (LAER) be met at all emission units.

Assuming the plant does restart operations soon and can legitimately do so without obtaining a major source NSR and PSD permit, UDAQ must make a BACT determination and impose BACT limits now to apply as soon as Lhoist North American begins operations.

Response to Comment 1: As the commenter has stated, the Lhoist North America - Grantsville Plant (LNA) was placed in temporary care and maintenance mode in November 2008. This means that the facility is still undergoing basic day-to-day activities such as security, plant clean-up operations, maintenance, etc. to remain in "ready mode" but no lime is being manufactured and the Rotary Kiln is not being operated (i.e., there is no fuel source being fired to keep the kiln heated) (*see* LNA BACT analysis, April 2017). As required by 40 CFR 51 Subpart Z, UDAQ must identify, adopt, and implement BACT on major sources of PM2.5 and PM2.5 precursors. LNA provided a BACT analysis to UDAQ on April 10, 2017 along with supporting information on August 28, 2017 and April 10, 2018. This analysis provided UDAQ with adequate information to establish limits for PM, PM2.5 (filterable and condensable), and NOx emissions. The BACT established limits were proposed and are listed in LNA's Part H limitation H.12.c. Further, prior to facility start-up LNA will be required to submit a Notice of Intent for review of the proposed control equipment discussed in Part H. The NOI will address BACT, emission limitations and any additional requirements prior to receipt of an Approval Order allowing the installation of the new control equipment.

Lastly, UDAQ does not revoke Approval Orders where the plant is currently being maintained for future operation or without a specific request by the company. Therefore, Approval Order DAQE-AN0707015-06 and the Title V permit #4500005003 shall remain active.

Comment 2: BACT for the Rotary Kiln System at Lhoist

One method of control for SO2 and to use in combination with controls for other pollutants that Lhoist failed to consider was using primarily natural gas to fire the rotary kiln system. It appears that, when Lhoist last operated, natural gas was the primary fuel. However, Lhoist's BACT analysis indicates that fuel oil can be used when natural gas delivery is curtailed, on-specification used oil can be used to supplement natural gas and fuel oil, and also tire-derived fuel can be used on an as needed basis.Sole use of natural gas is the cleanest fuel to use from a PM2.5 perspective, and thus should be the first consideration in the BACT analysis for the rotary kiln, by itself and in combination with other controls. For example, in the NOx BACT analysis, Lhoist dismissed use of low NOx burners in part due to the use of multiple fuels at the Lhoist rotary kiln, claiming that other kilns that have successfully used low NOx burners burned one type of fuel. Lhoist should have considered sole use of natural gas in combination with other controls including low NOx burners in the BACT analysis.

Response to Comment 2: UDAQ disagrees with this comment. LNA is approved to utilize pipeline quality natural gas, fuel oil (diesel), on-specification used oil, and tire derived fuel (TDF) in the rotary kiln. LNA primarily burns natural gas as fuel but does require the use of fuel oil, on-specification used oil, and/or tire derived fuel to better assist the rotary kilns operating temperature. The most prevalent control of SO2, as listed in the EPA's RBLC is fuel sulfur limitations and "inherent" sulfur control. The alkaline properties of limestone tend to neutralize acid gases and that limestone has a scrubbing effect that reduces SO2 emissions. Add on controls such as flue gas desulfurization (which uses lime to control SO2 emissions) is typically utilized at sources which have high SO2 concentrations in the flue gas. A flue gas desulfurization control option was evaluated in the BACT analysis (*see* BACT analysis Appendix A, April 1017). A final BACT value for SO2 control was concluded to be $80,000 per ton of SO2 removed. Therefore, flue gas desulfurization was ruled out as a SO2 control option due to excessive cost.

Additionally, the LNA facility uses pipeline quality natural gas which is low in sulfur. Source testing has been performed for the TDF system and SO2 emissions were demonstrated to be higher for combustion of natural gas than TDF which showed non-detectable limits for SO2 concentrations. Conditions II.B.1.d and II.B.3.e of the Title V Operating Permit #4500005003 limits the sulfur content from fuel oil and on-specification used oil which is further reduced again through the inherent sulfur control discussed above.

Lastly, UDAQ did evaluate Low NOx burners in the BACT review. The use of Low NOx burners in lime kilns is not a widely used control technology, and past use of bluff body low NOx burner systems at other LNA facilities was not successful. A search of the EPA's RBLC for lime kiln permits confirmed this result. None of the recent permitting actions have determined low NOx burner systems to be BACT, except an action for Western Lime Corporation. This permit utilized a straight pipe with a bluff body burner which Grantsville does not implement. Also, as stated above, LNA has experimented with bluff body low NOx burner systems and was not successful.

Comment 3: Lhoist proposed a fabric filter baghouse as BACT but requested not to select which type of baghouse to install until "a later date" due to the facility "being in care and maintenance mode." What is most important at this point is for UDAQ to set an emissions limit reflective of BACT for PM2.5 from the rotary kiln. A review of the RBLC shows that the lowest PM2.5 emission limit for rotary kilns is 0.1050 lb/ton, 3-hour average, with some exceptions for low capacity during which a 5.24 lb/hr limit applies over a 3-hour average (RBLC ID IL-0177, Mississippi Lime Company). In addition, numerous facilities are also subject to an opacity BACT limit, with the lowest being a 10% opacity limit on a 6-minute average with some exceptions (RBLC ID PA-0283, Graymont PA Inc./Pleasant Gap & Bellefonte Plants). There is also visible emission BACT limits for rotary kilns of 15% opacity limit on a 6-minute average with no exceptions (RBLC ID FL-0321, Jacksonville Lime, and RBLC ID OH-0321, Martin Marietta Materials). It must be noted that the definition of BACT includes a visible emissions limit. Thus, UDAQ must impose BACT limits no higher than these limits on the rotary kiln system at Lhoist applicable upon startup. Yet, UDAQ has not proposed any PM2.5 BACT limits for the rotary kiln system. This is a significant deficiency in UDAQ's BACT analysis for Lhoist.

Response to Comment 3: UDAQ disagrees with this comment as PM2.5 BACT limits have been proposed in Part H.c.12 for LNA. LNA currently employs an electroscrubber for control of PM10 emissions. The BACT analysis performed reviewed a baghouse control device which demonstrated that the cost per ton removed for PM10/PM2.5 emissions from the rotary kiln is estimated at $91,642 (*see* site specific cost effectiveness value in RACT analysis dated August 2013). While this cost is quite high, LNA agreed to install the baghouse prior to facility start-up.

The established BACT analysis considered the current "care and maintenance mode" of the facility and the fact that a PM2.5 emission limit needs to contain a filterable and condensable limitation. Therefore, the BACT emission limitation was based upon LNA's experience, performance testing for other kiln sources and AP42 calculated emissions for condensables. While the commenter listed PM2.5 emission limitations in the RBLC, they failed to state if the 0.1050 lb/ton (3-hour average) and exception for low capacity limit of 5.24 lb/hr limits were filterable only or filterable plus condensable limits. Also the commenter failed to recognize that the emission limitations discussed were in units of lb/hr or lb/ton and the LNA Part H.c.12 limitations are in units of lb/ton of stone feed which may not be equivalent units.

Lastly, UDAQ requires BACT to be established through a variety of methods which can be accomplished through performance (emission) based limits or visual opacity limitations. Commenter fails to recognize that BACT does not require a visual opacity limitation in conjunction with an emissions limit. LNA Part H.c.12 limitations establish emission based limits only. Any opacity limits associated with the on-site equipment will be established in the updated Approval Order issued prior to facility start-up.

Comment 4: Instead, Lhoist has proposed to meet the existing lime kiln MACT limit for filterable PM of 0.12 lb/ton of stone feed (adjusted to reflect 37% of PM being of the size PM2.5 or smaller) and has proposed a total PM2.5 limit of 1.4324 lb/ton of stone feed based on condensable PM2.5 testing of other Lhoist North America facilities. This is not how a BACT emission limit is to be set. First, BACT is to be based on a top-down analysis, not a bottom-up analysis. Further, there is no basis for assuming the existing kiln MACT limit should be the BACT floor and not the new kiln MACT limit of 0.10 lb filterable PM per ton of stone feed. In addition, Lhoist provided no BACT analysis to justify that its proposed total PM2.5 (filterable plus condensable) limit of 1.4324 lb/tons of stone feed reflects the maximum degree of emission reduction achievable. For example, it is not known what fuels the other Lhoist kilns were utilizing. It is most likely that burning natural gas produces the lowest emissions of condensable (as well as filterable) PM2.5. UDAQ must require that the PM2.5 emission limits required as BACT are set based on a proper top-down analysis reflective of the maximum degree of PM2.5 emission reduction achievable, considering the cost and other factors that are weighed in a BACT determination.

Response to Comment 4: UDAQ conducted a BACT review for each emission unit for all major sources, as required in the PM2.5 implementation rule. A top down analysis was performed for the PM2.5 Moderate SIP review. The analysis performed considered cyclone separators, spray towers, venturi scrubbers, baghouses, and electrostatic precipitators. The analysis for the baghouse concluded that the cost per ton removed for PM2.5 emissions from the rotary kiln was estimated at $91,642 (*see* site specific cost effectiveness value in RACT analysis dated August 2013). While the cost per ton removed is quite high, LNA agreed to install the baghouse prior to facility start-up. As actual emissions are not available at this time, UDAQ examined potential emissions from lime kilns in the RBLC. The vast majority of the RBLC sources were fired on coal and/or petroleum coke and were subject to Maximum Achievable Control Technology (MACT) requirements under 40 CFR 63 Subpart AAAAA for the control of hazardous air pollutants. Particulate emissions are used as a surrogate for HAP emissions (which will be mostly solids) and therefore the MACT emission standards were based on particulates emitted per ton of stone feed (lb/tsf). The MACT limits are based on the top 12% of performing emission sources in a category and therefore represent a very stringent control level. The particulate limit of 0.12 lb/tsf, for existing kilns, is heavily reflected in the RBLC and therefore was set as an appropriate emission limit from the baghouse. The commenter did not provide any documentation to demonstrate that the Part H limitations of 0.12 lb/tsf was not acceptable.

Comment 5: With respect to BACT for SO2 emissions, Lhoist states that SO2 emissions are mainly due to the sulfur content of the fuel used in the kiln. Thus, sole use of natural gas to minimize SO2 emissions to the greatest extent should have been reviewed as an SO2 control in the BACT analysis. While Lhoist provided anecdotal information in its BACT analysis that burning of tire- derived fuel which has approximately 1.2% sulfur content did not increase SO2 emissions, Lhoist did not provide any specific test data to back that claim up. Further, Lhoist made no claims regarding SO2 emissions from the kiln during the burning of oil, other than to say the sulfur content of those fuels are limited by a permit condition. There is no question that these n higher sulfur content than natural gas. Given that natural gas is the primary fuel used in the rotary kiln, it would likely be extremely cost effective to simply stop utilizing oil or tire-derived fuel to meet SO2 BACT. Yet, UDAQ did not even evaluate sole use of natural gas as an SO2 BACT control option. UDAQ must review this very reasonable control option for the Lhoist rotary kiln system.

Response to Comment 5: ***See response to Comment 2 above for LNA.***

Comment 6: Lhoist has proposed selective noncatalytic reduction (SNCR) to meet BACT for NOx. However, in proposing a NOx emission limit reflective of BACT, Lhoist proposed the low end of achievable NOx reductions with SNCR of 25% and applied that to the current NOx limit of the operation permit for Lhoist's Grantville Plant of 75.00 lb/hr. UDAQ has also assumed the same 25% level of control in proposing a NOx BACT limit of 56 lb/hr. When a BACT control can operate at a range of control efficiencies, the BACT analysis must include an evaluation of the control at the top control efficiency. If Lhoist claims no higher NOx removal efficiency than 25% can be achieved with SNCR at its Lhoist lime kiln, then it needs to document why. In addition, it does not necessarily make sense to propose a limit based on 25% control from the current NOx limit of 75.00 lb/hr. It could be that actual emissions from the lime kiln have been significantly lower than 75.00 lb/hr. Lhoist should document what the lime kiln's actual NOx emissions were based on actual test data and the fuel mix being utilized. Then the proposed limit should be based on the maximum achievable control with SNCR, taking into account the various BACT factors, with a margin of safety for compliance.

Although Lhoist evaluated the cost effectiveness of low NOx burners based on 30% control, the company claimed that such levels of NOx control could not be universally achieved. Yet, Lhoist did not provide any documentation to support this claim. UDAQ's analysis included some anecdotal claims to support Lhoist claims, but did not provide much supporting documentation. Given that low NOx burners could achieve greater than the 25% NOx control proposed by Lhoist as BACT and at lower costs, Lhoist must be required to provide sufficient documentation to support eliminating low NOx burners as a control.

In addition, as described above, Lhoist should be required to evaluate whether low NOx burners could work effectively at its lime kiln if the kiln was limited to solely natural gas combustion, which would better allow for maintaining burner performance due to the consistency of the fuel NOx and other related fuel characteristics. If such burners could work with the kiln solely utilizing natural gas, the NOx emission reductions would be greater than with SNCR at lower costs than SNCR and with no concerns about ammonia slip. In addition, assuming low NOx burners would be more viable as a NOx control with natural gas as the sole fuel, Lhoist should also be required to evaluate the NOx reductions and cost effectiveness with both low NOx burners and SNCR installed, which could provide the maximum reduction in NOx emissions from the lime kiln.

Response to Comment 6: UDAQ disagrees with the comment. SNCR utilizes either ammonia or urea as a reagent in a high temperature environment (typically 1600 to 2100 degrees F) to control NOx via a reduction reaction. The flue gas temperature for the rotary kiln is around 345 degrees F, which would result in an extremely low reaction rate and reduce SNCR effectiveness. Because this the use of SNCR would require the installation of a heat exchanger to heat up the gas stream and make the control efficiency in question. Therefore, UDAQ assumed 25% control was conservative in establishing appropriate control efficiency and was independent of the fuel being combusted.

Also, in evaluation of the NOx limitation, UDAQ feels establishing the limit of 56 lb/hr (25% control efficiency) was appropriate considering the fact that the plant in not in full scale operation and there are currently no lime kilns outfitted with SNCR to control NOx emissions. Commenter also failed to provide any documentation or suggested NOx limitation that should have been considered as part of the analysis.

Comment 7: Last, Lhoist did not propose any BACT emission limit for ammonia emissions from the SNCR and instead based BACT on good combustion processes and burner/process optimization. However, with the addition of SNCR to control NOx and the likely level of ammonia slip from the SNCR, it is imperative that an ammonia BACT limit be set for the Lhoist facility. UDAQ did propose an ammonia slip limit of 10 ppm as BACT. While we agree that a limit on ammonia is warranted for Lhoist (indeed, there are several examples of pound per hour ammonia BACT limits in the RACT/BACT/LAER Clearinghouse), UDAQ did not conduct any analysis to show that this level of ammonia slip actually represents BACT for Lhoist. UDAQ itself noted that permits for SCR at large combustion turbines have limited ammonia slip emissions at lower levels of 2.0 ppm and 5.0 ppm. UDAQ must conduct a proper BACT analysis for ammonia slip to ensure it is requiring the maximum reduction in ammonia emissions that is achievable considering the other BACT factors. Further, UDAQ must impose the ammonia slip limit as an enforceable requirement (it currently is not listed in draft Section IV Part H of the Utah SIP) and must require ammonia monitoring to ensure compliance.

Response to Comment 7: UDAQ disagrees with this comment. With the installation of SNCR there is a potential for ammonia slip. However, the likelihood of being able to pin it down to an exact range is difficult. This was addressed in response to Comment 6 above in that the plant is not in full scale operation and there are currently no lime kilns outfitted with SNCR to control NOx emissions. Therefore, determining an appropriate ammonia slip limitation would not be effective in ensuring compliance and proper source operation as it is new equipment. Commenter also failed to provide any documentation or suggested ammonia slip limitations specific to lime kilns for this analysis. The 2.0 ppm and 5.0 ppm limits Commenter discussed were for combustion turbine units with SCR which are not comparable to a lime kiln with SNCR. In order to select a BACT option, UDAQ discussed an ammonia slip limit of 10.0 ppm in the TSD document but will establish this BACT requirement through an Approval Order as well as the Title V Operating Permit.

No changes were made to TSD or Part H limits as the result of Comments 1 through 7.

H-62[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, Utah Physicians for a Healthy Environment, and Heal Utah]: Review of BACT Analyses for ATK *(see VI. Technical Report. August 14, 2018)*

Response to H-62: General Comment Responses

Comment 1: According to ATK's May 2017 BACT analysis, ATK operates 21 natural gas-fired boilers and 19 fuel oil-fired boilers (163, May 2017 ATK BACT Analysis at 1.) ATK appears to have eliminated most of these boilers from BACT review. For example, ATK only evaluated NOx BACT for the largest gas-fired boilers of 25 MMBtu/hour or greater (164, Id. at 24). For the diesel-fired boilers, ATK relies on the existing ultra-low sulfur fuel requirement (<15 ppm sulfur) to reflect BACT for all PM2.5 and PM2.5 precursors from these emission units. ATK did not provide any analysis of BACT for any of the diesel-fired boilers. *<u>UDAQ's BACT evaluation tacitly approves of only focusing on the "four largest natural gas boilers," and UDAQ failed to provide any justification to eliminate the other boilers from a BACT analysis (165, July 1, 2018 UDAQ PM2.5 SIP Evaluation Report – ATK [DAQE-2018-007203], at 13).</u>*

Response to Comment 1: ATK has 17 fuel oil-fired boilers that operate solely on fuel oil due the lack of availability of natural gas. These fuel oil-fired boilers capacity and locations are as follows: Building M-205~5.23 MMBtu/hr, Building M-205~8.37 MMBtu/hr, Building M-338~2.51 MMBtu/hr, Building T-001~2.09 MMBtu/hr, Building T-004A~0.84 MMBtu/hr, Building T-006A~2.09 MMBtu/hr, Building T-014E~6.15 MMBtu/hr, Building T-015A~1.67 MMBtu/hr, Building T-017A~2.09 MMBtu/hr, Building T-018A~1.67 MMBtu/hr, Building T-021A~3.35 MMBtu/hr, Building T-023~1.05 MMBtu/hr, Building T-024A~2.51 MMBtu/hr, Building T-051A~2.51 MMBtu/hr, Building T-097A~4.18 MMBtu/hr, Building T-111~5.23 MMBtu/hr, and Building T-111~5.23 MMBtu/hr.

The largest fuel oil-fired boiler at the remote test site is 8.37 MMBtu/hr. The estimated emissions for a 5 MMBtu/hr fuel oil-fired boiler are 3.13 ton per year of NOX, 0.78 tons per year of CO, and 0.52 tons per year of PM10/2.5 (based upon 8760 hours of operation a year and uncontrolled). The ability to install retro fit control technologies on oil-fired boilers of this size is not economically feasible. The cost of replacing fuel oil-fired boilers with propane-fired boilers is not economically feasible. It has been determined by UDAQ that limited use (by a fuel limitation), ulta-low sulfur fuel and good combustion practices is BACT for oil fuel-fired boilers less than 10 MMBtu/hr.

ATK has 19 natural gas-fired boilers located in the South area. These natural gas-fired boilers capacity and location are as follows; Building A-009~8.37 MMBtu/hr, Building A-009~8.37 MMBtu/hr, Building A-009~8.37 MMBtu/hr, Building M-010~8.37 MMBtu/hr, Building M-010~8.37 MMBtu/hr, Building M-010~8.37 MMBtu/hr, Building M-14~25.11 MMBtu/hr, Building M-14~25.11 MMBtu/hr, Building M-033~8.37 MMBtu/hr, Building M-033~8.37 MMBtu/hr, Building M-033~12.55 MMBtu/hr, Building M-033~16.74 MMBtu/hr, Building M-072~8.37 MMBtu/hr, Building M-072~8.37 MMBtu/hr, Building M-072~12.55 MMBtu/hr, Building M-348~6.28 MMBtu/hr, Building M-576~71.10 MMBtu/hr, Building M-576~71.10 MMBtu/hr, and Building M-705~12.55 MMBtu/hr.

The estimated emissions for a 10 MMBtu/hr natural gas-fired boiler is 4.29 ton per year of NO_X, 3.61 tons per year of CO, and 0.33 tons per year of $PM_{10/2.5}$ (based upon 8760 hours of operation a year, uncontrolled). The ability to install retro fit control technologies on sources of this size is not economically feasible. It has been determined by UDAQ that limited use (by fuel limitation) and good combustion practices are BACT for natural gas-fired boilers less than 10 MMBtu/hr (11 out of 19 boilers).

ATK has six natural gas-fired boilers that exceed 10 MMBtu/hr but less than 30 MMBtu/hr. The estimated emissions for a 30 MMBtu/hr natural gas-fired boiler is 12.88 ton per year of NO_X, 10.82 tons per year of CO, and 0.98 tons per year of PM10/2.5 (based upon 8760 hours of operation a year, uncontrolled). It has been determined by UDAQ that limited use (by fuel limitation) and good combustion practices are BACT for natural gas-fired boilers less than 30 MMBtu/hr (6 out of 19 boilers).

One natural gas-fired boiler (of the 6 natural gas-fired boilers that exceed 10 MMBtu/hr but less than 30 MMBtu/hr) has the heat input capacity of 12.55 MMBtu/hr and the NOX emissions rate of 9 ppm NO_X. ATK has recently replaced an old 10 MMBtu/hr boiler with a new 12.55 MMBtu/hr boiler. The old 10 MMBtu/hr boiler had exceeded its lifespan. The new 12.55 MMBtu/hr boiler has a 9 ppm NO_X emissions rate and was installed as a replacement of an old boiler and not an old boiler being upgraded with new controls.

Two (of the 6 natural gas-fired boilers that exceed 10 MMBtu/hr but less than 30 MMBtu/hr) natural gas-fired boilers have the heat input capacity of 25.11 MMBtu/hr. The two 25.11 MMBtu/hr boilers were analyzed, through a BACT analysis, and concluded that the two boilers with the input heat capacity 25.11 MMBtu/hr are to be upgraded to an emissions rate of 9 ppm NO_X at a cost of $9,300 per ton removed of NO_X. ATK has agreed to upgrade the two 25.11 MMBTU/hr boilers to 9 ppm NO_X but has requested an extended implementation date of December 31, 2024.

ATK has two natural gas-fired boilers that exceed 30 MMBtu/hr. Building M-576 has two boilers rated at 71.10 MMBtu/hr. One of the two boilers have been upgraded to lower the NO_X emissions to 9 ppm. The second existing uncontrolled NO_X boiler with the heat input capacity of 71.10 MMBtu/hr boiler is not being upgraded but being utilized as backup (to the 71.10 MMBtu/hr, 9 ppm NO_X boiler) with a natural gas consumption limitation of 100,000 MCF per rolling 12 month. The boiler upgrade would require ATK to alter the existing building dimensions (increasing the cost of ton removed) to accommodate for the additional space needed.

Comment 2: In its October 2016 RACT submittal, ATK referred to natural gas and fuel oil consumption limits placed on the boilers to satisfy RACT (166, May 2017 ATK BACT Analysis at 24). However, such limits have not been demonstrated to meet BACT, and additional control measures are readily available. According to the Title V permit for ATK Promontory Site, the sizes of the diesel-fired boilers are in the range of 0.84 MMBtu/hr to 8.37 MMBtu/hr (167, See Conditions II.A.95 through II.A.111 of Title V Permit). All diesel-fired boilers are required to fire only ultra-low sulfur diesel (<0.0015% sulfur)(168, See Condition II.B.27.a. of Title V Permit), and are apparently subject to a total limit of 1,298,400 gallons of fuel oil per 12-month period (169, See Condition II.B.30.a.B. of Title V Permit) While the annual limit on fuel oil burned will limit total operation of the 19 fuel oil-fired boilers at ATK Promontory, it is not clear whether, and seems quite plausible that, some of these boilers are utilized more frequently than others and thus may warrant more thorough evaluation of BACT controls. *UDAQ must require ATK to identify the actual operating hours and annual heat input for each of these boilers to enable a more thorough review of BACT – primarily NOx BACT- for these boilers. For those units operated more frequently, ATK should evaluate low excess air (LEA) firing, flue gas recirculation (FGR), staged combustion, low NOx burners and other NOx reduction measures, even for the units smaller than 25 MMBtu/hour. UDAQ did not provide any justification to exclude smaller units from a BACT evaluation.*

Response to Comment 2: The 17 fuel oil-fired boilers have the following location and heat input capacity: These fuel oil-fired boilers heat input capacity and locations are as follows: Building M-205~5.23 MMBtu/hr, Building M-205~8.37 MMBtu/hr, Building M-338~2.51 MMBtu/hr, Building T-001~2.09 MMBtu/hr, Building T-004A~0.84 MMBtu/hr, Building T-006A~2.09 MMBtu/hr, Building T-014E~6.15 MMBtu/hr, Building T-015A~1.67 MMBtu/hr, Building T-017A~2.09 MMBtu/hr, Building T-018A~1.67 MMBtu/hr, Building T-021A~3.35 MMBtu/hr, Building T-023~1.05 MMBtu/hr, Building T-024A~2.51 MMBtu/hr, Building T-051A~2.51 MMBtu/hr, Building T-097A~4.18 MMBtu/hr, Building T-111~5.23 MMBtu/hr, and Building T-111~5.23 MMBtu/hr.

UDAQ finds it unreasonable to identify the actual operating hours of each fuel oil-fired boiler and perform an analysis based upon the actual operating hours. The analysis would require DAQE to put specific hourly limit on each fuel oil-fired boiler. ATK must maintain flexibility in the operation of test sites which requires the flexible operation of the fuel oil-fired boilers.

ATK does not have any fuel oil-fired boilers with a heat input capacity above 10 MMBTU/hr. The largest fuel oil-fired boiler at the remote located test site 8.37 MMBtu/hr. The estimated emissions for a fuel oil-fired boilers with a heat input capacity 5 MMBtu/hr are 3.13 ton per year of NO_X, 0.78 tons per year of CO, and 0.52 tons per year of $PM_{10/2.5}$ (based upon 8760 hours of operation a year and uncontrolled). The ability to install retro fit control technologies on oil-fired boilers of this size is not economically feasible. The cost of replacing fuel oil-fired boilers with propane-fired boilers is not economically feasible with extensive natural gas trucking cost to a remote location. It has been determined by UDAQ that limited use (by a fuel limitation), ulta-low sulfur fuel (0.0015% sulfur content by weight) and good combustion practices is BACT for oil fuel-fired boilers with a heat input capacity less than 10 MMBtu/hr.

Comment 3: While all of the ATK diesel-fired boilers are subject to periodic tune-up requirements, some units are subject to more frequent tune-up requirements based on size of the boiler (170, See Condition II.B.34.b. of the Title V Permit). These requirements appear to be based on provisions in 40 CFR Part 63, Subpart DDDDD (171,Id). *Regardless of whether a boiler is subject to Subpart DDDDD, these more frequent tune-up requirements clearly could be required on all boilers annually (as is currently required for boilers with a heat input capacity greater than 10 MBtu/hr pursuant to Condition II.B.34.b.(3) of the ATK Title V permit).* Boiler tune-ups can lower NOx and PM2.5 emission rates, among other pollutants, and more frequent tune-ups can more consistently ensure lower emission rates. Thus, UDAQ and ATK must at the minimum consider annual tune-ups for all diesel-fired boilers.

Response to Comment 3: ATK is subject to the tune-up requirements of 40 CFR 63 Subpart DDDDD where applicable. The remaining boiler and heaters are mainly small comfort or space heating units and water heaters less than 120 gallons or less than 1.6 MMBtu/hr heat input capacity. The units are exempt from the requirements of 40 CFR 63 Subpart DDDDD as well as the requirement to obtain an approval order. The EPA estimated in the development of 40 CFR 63 Subpart DDDDD [see "Regulatory Impact Results for the Reconsideration Final Rule for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources", December 19, 2012] that tune-ups would result in a 1% reduction in the amount of fuel consumed. The small boilers are exempt from the requirements of 40 CFR 63 Subpart DDDDD as well as the requirement to obtain an approval order, but are covered under UAC R307-230-3 "NO_X Emission Limits for Natural Gas-Fired Water Heaters". UDAQ has all other boilers listed in the Approval Order, not subject to 40 CFR 63 Subpart DDDDD, operating and maintaining boilers in a manner consistent with good air pollution control practices for minimizing emissions (DAQE-AN100090133-16, Condition I.5). This involves boiler tune-ups as per manufactures recommendation for all boilers not subject to 40 CFR 63, Subpart DDDDD.

Comment 4: For the natural gas-fired boilers, ATK has failed to provide a thorough analysis of NOx BACT. ATK indicates that it has upgraded a 71 MMBtu/hr boiler with an ultra-low NOx burner which has a NOx emission rating of 9 ppm (172, May 2017 ATK BACT Analysis at 18). The title V permit for ATK Promontory also indicates that a 12.55 MMBtu/hr boiler has a NOx emission rate of 9 ppm (173, See Title V Permit Condition II.A.86). Yet, there are numerous other natural gas-fired boilers of similar size for which ATK did not evaluate any low NOx burners. *ATK only very minimally evaluated low NOx burners as BACT for the other 71 MMBtu/hr boiler that has a NOx emission rate of greater than 30 ppm (174, See Title V Permit Condition II.A.90), more than 4 times higher than the NOx rating of the boiler with an ultra-low NOx burner. Indeed, ATK has previously indicated that when operating in standby mode, NOx emissions from this other 71 MMBtu/hr boiler are approximately 50 ppm (175, October 2016 ATK RACT Analysis at 3), which is 5.6 times higher than the 9 ppm rate achieved with the ultra-low NOx burner.*

Response to Comment 4: Building M-576 houses two boilers rated at 71.10 MMBtu/hr. One of the two boilers have been upgraded to lower the NO_X emissions to 9 ppm which already been conducted. The existing uncontrolled NO_X boiler with the input heat capacity of 71.10 MMBtu/hr has been limited to 100,000 MCF of natural gas consumed. ATK has committed to DAQ that if work load increase requiring additional steam demand that the existing uncontrolled NO_X boiler will be upgraded to 9 ppm NO_X and ATK will absorb the additional cost of building reconstruction for the upgrades. ATK has committed to operate the existing uncontrolled NO_X boiler minimally to maximize the operational flexibility with the 100,000 MCF natural gas consumption limit.

Comment 5: ATK claimed in its BACT submittal that the higher NOx-emitting 71 MMBtu/hr boiler only operates as backup capacity and is restricted to an annual natural gas limit (176, May 2017 ATK RACT analysis at 18). However, that 12-month rolling limit on the amount of natural gas fired does not limit the boiler's operations on a daily basis, and thus the boiler could significantly contribute to daily PM2.5 concentrations when it operates*. Moreover, given that it was cost effective for ATK to install an ultra-low NOx burner on one of the 71 MMBtu/hr boilers, it should be assumed that it is also cost effective to install an ultra-low NOx burner on the other 71 MMBtu/hr boiler. If ATK is claiming that it is less cost effective to install a low NOx burner on the "standby" 71 MMBtu/hr boiler due to the 100,000 million cubic feet gas consumption limit that applies to the unit on a 12- month basis, ATK needs to document how that differs from the other 71 MMBtu/hr boiler's operations, especially because all of the gas-fired boilers at the ATK Promontory site are subject to a rolling 12-month limit on natural gas consumption of 1,046,000,000 standard cubic feet of natural gas per 12-month period (177, ATK Title V Permit Number 300003003 at Condition II.B.30.a).*

Response to Comment 5: The second existing uncontrolled NO_X boiler with the heat input capacity of 71.10 MMBtu/hr is not being upgraded but is limited in operations and being utilized as backup (to the 71.10 MMBtu/hr, 9 ppm NO_X boiler). The existing boiler upgrade would require ATK to alter the existing building dimensions (increasing the cost of ton removed) to accommodate for the additional space needed. An effective emissions control method, for existing equipment, with a high cost per ton removed ($15,151 per ton of NO_X removed), is to limit the operation either by hours of operations or fuel consumed. ATK has elected to limit the natural gas consumed (100 MCF) by the existing uncontrolled NO_X boiler based upon the uncertain work load. ATK has committed to DAQ that if ATK's work load increase requiring additional steam demand that the existing uncontrolled NO_X boiler will be upgraded to 9 ppm NO_X and ATK will absorb the additional cost of building reconstruction for the upgrades.

Comment 6: Further, *the operating hours and days of the higher NOx emitting boiler that did install an ultra-low NOx burner are not given and it is not clear that the 71 MMBtu/hr boiler with the recently-installed ultra-low NOx burner is operated continuously.* As previously stated, all of the boilers at the ATK site are subject to a total 12-month gas limit of 1,046,000,000 standard cubic feet per 12 month period, as stated above (178, ATK Title V Permit at Condition II.B.30.a.A). Thus, the operating hours of the 71 MMBtu/hr boiler with the ultra-low NOx burner is also somewhat limited, and yet ultra-low NOx burners were still considered cost effective.

Response to Comment 6: ATK has a rolling 12-month total natural gas limit (1,046 MCF) for all boilers listed in the Approval Order. The second existing uncontrolled NO_X boiler with the heat input capacity of 71.10 MMBtu/hr has a limit of 100 MCF per rolling 12-months. The 1,046 MCF of natural gas consumed includes the 100 MCF of natural gas consumed limit for the second existing uncontrolled NO_X boiler. The limitation on the second existing uncontrolled NO_X boiler effects both 1,046 MCF and 100 MCF natural gas consumption limits. The updated (9 ppm NO_X) 71 MMBtu/hr boiler has only one natural gas consumption limit (1,046 MCF) for all boilers covered in the Approval Order.

Comment 7: …Indeed, an ultra-low NOx burner with a NOx emission rating of 9 ppm has been installed and thus found cost effective for a 12.55 MMBtu/hr boiler at the ATK Promontory site (179, See Title V Permit at Condition II.A.86). If such controls on similarly and smaller sized gas-fired boilers have been found to be cost effective, than such controls must be required as BACT for the currently uncontrolled 71 MMBtu/hr boiler as well as the other four gas-fired boilers of similar or greater heat input (180, See Title V Permit at II.A.88 (two gas fired boilers of 25.11 MMBtu/hr each) and at II.A.89 (two gas fired boilers of 16.74 MMBtu/hr each)) to the 12.55 MMBtu/hr boiler. *As EPA has stated, when a similar source has installed a control technology, it should be considered cost effective for the source in question, absent significant cost differences for the source being evaluated for BACT* (181, See EPA's October 1990 New Source Review Workshop Manual at B.31).

Response to Comment 7: ATK has recently replaced an old 10 MMBtu/hr boiler with a 12.55 MMBtu/hr boiler. The old 10 MMBtu/hr boiler had exceeded its lifespan. ATK will replace existing boilers with new boilers with better emissions controls when boilers are phased out operation. The 12.55 MMBtu/hr boiler that has the 9 ppm NO_X emissions rate was a replacement of an old boilers and not an old boiler being upgraded with new controls. In this case it was cost effective to install a new 12.55 MMBtu/hr boiler with an emissions rate of 9 ppm. When boiler lifespans are exceeded, DAQE will use current BACT (9 ppm NO_X) to update the Approval Order. The commenter states EPA cost effectiveness but does not acknowledge the difference between equipment replacement due to lifespan vs updating equipment controls.

Comment 8: UDAQ seems to have accepted these discrepancies in the NOx BACT analyses for the natural gas-fired boilers without question (182, July 1, 2018 UDAQ PM2.5 SIP Evaluation Report – ATK [DAQE-2018-007203], at 15). *UDAQ must adequately address and document why upgrading the higher NOx-emitting boiler is not justified as BACT.*

Response to Comment 8: The commenter does not specify which natural gas-fired they are commenting on. DAQ is assuming that the commenter is addressing the second existing uncontrolled NO_X boiler with the heat input capacity of 71.10 MMBtu/hr. The second existing uncontrolled NO_X boiler with the heat input capacity of 71.10 MMBtu/hr is not being upgraded but is limited in operations and being utilized as backup (to the 71.10 MMBtu/hr, 9 ppm NO_X boiler). The existing boiler upgrade would require ATK to alter the existing building dimensions (increasing the cost of ton removed) to accommodate for the additional space needed. An effective emissions control method, for existing equipment, with a high cost per ton removed ($15,151 per ton of NO_X removed), is to limit the operation either by hours of operations or fuel consumed. ATK has elected to limit the natural gas consumed (100,000 MCF) by the existing uncontrolled NO_X boiler based upon the uncertain work load. ATK has committed to DAQ that if ATK's work load increase requiring additional steam demand that the existing uncontrolled NO_X boiler will be upgraded to 9 ppm NO_X and ATK will absorb the additional cost of building reconstruction for the upgrades.

Comment 9: In addition, similar to the diesel-fired boilers, all of the gas-fired boilers are subject to periodic tune-up requirements, with some units are subject to more frequent tune-up requirements based on size of the boiler (183, See Condition II.B.31.b. of the Title V permit). These requirements appear to be based on provisions in 40 CFR Part 63, Subpart DDDDD (184, Id). Regardless of whether a boiler is subject to Subpart DDDDD, these requirements clearly could be required on all gas-fired boilers annually (as is currently required for boilers with a heat input capacity greater than 10 MMBtu/hr pursuant to Condition II.B.31.b.(3) of the ATK Title V permit). Boiler tune-ups can lower NOx emission rates from gas-fired boilers, among other pollutants, and more frequent tune-ups can more consistently ensure lower emission rates. *Thus, UDAQ and ATK must at the minimum consider annual tune-ups for all gas-fired boilers. And, as discussed above, for those ATK gas-fired boilers of heat input capacity of 12.55 MMBtu/hr heat input or greater, ultra-low NOx burners should be considered as BACT* unless ATK can show significant differences in costs of this control for the gas-fired boilers that are not currently equipped with this control at the ATK Promontory site.

Response to Comment 9: ATK is subject to the tune-up requirements of 40 CFR 63 Subpart DDDDD where applicable. The remaining boiler and heaters are mainly small comfort or space heating units and water heaters less than 120 gallons or less than 1.6 MMBtu/hr capacity. The units are exempt from the requirements of 40 CFR 63 Subpart DDDDD as well as the requirement to obtain an Approval Order. The EPA estimated in the development of 40 CFR 63 Subpart DDDDD [see "Regulatory Impact Results for the Reconsideration Final Rule for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources", December 19, 2012] that tune-ups would result in a 1% reduction in the amount of fuel consumed. The small boilers are exempt from the requirements of 40 CFR 63 Subpart DDDDD as well as the requirement to obtain an approval order, but are covered under UAC R307-230-3 "NO_X Emission Limits for Natural Gas-Fired Water Heaters". UDAQ has all other boilers listed in the Approval Order, not subject to 40 CFR 63 Subpart DDDDD, operating and maintaining boilers in a manner consistent with good air pollution control practices for minimizing emissions (DAQE-AN100090133-16, condition I.5). This involves boiler tune-ups as per manufactures recommendation for all boilers not subject to 40 CFR 63, Subpart DDDDD.

ATK has four natural gas-fired boilers that exceed 10 MMBtu/hr but less than 20 MMBtu/hr. The four natural gas-fired boilers are located and have the following heat input capacity; Building M-033~12.55 MMBtu/hr, Building M-033~16.74 MMBtu/hr, Building M-072~12.55 MMBtu/hr and Building M-705~12.55 MMBtu/hr. The boiler in building M-705 is a replacement of a boiler that exceeded its lifespan and has a NO_X emissions rate of 9 ppm. The other three boilers (Building M-033~12.55 MMBtu/hr, Building M-033~16.74 MMBtu/hr, Building M-072~12.55 MMBtu/hr) are getting to the end of their lifespan (within 10 years) and the cost of retrofitting boilers with ultra-low NOX burners is not cost effective ($13,506 per ton removed for NO_X).

H-63[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, Utah Physicians for a Healthy Environment, and Heal Utah]: Review of BACT Analyses for Hill Air Force Base *(see VII. Technical Report. August 14, 2018)*

Hill Air Force Base (HAFB) is located in Davis and Weber Counties about 30 miles north of Salt Lake City, and has industrial facilities for painting, paint stripping, plating, parts warehousing/distribution, and wastewater treatment (185, Hill Air Face Base-Main Base Title V Permit Number 1100007003 at 2). These comments focus on BACT for SO2 for the units that fire diesel fuel, as well as BACT for the 97 emergency generators and the three landfill gas generators at the Hill Air Force Base for which the PM2.5-impacting pollutants are NOx, PM2.5 and VOCs (186, April 25, 2017 Hill Air Force Base BACT Submittal at 2-1).

Response to H-63: General Comments 1 - 8

Comment 1:
It is not clear which generators at HAFB primarily fire diesel fuel and which primarily fire natural gas. The HAFB BACT submittal implies that the generators fire both natural gas and diesel and cites to variable fuel sources as a reason to not eliminate the most effective NOx control - SCR – from the BACT evaluation. However, presumably these generators predominately fire one source of fuel. For example, in the Title V permit for HAFB, the "Aggregated Boiler Group" and the "NSPS Boilers" are described as "natural gas-fired" boilers that are capable of burning diesel and other fuels (188, Hill Air Face Base-Main Base Title V Permit Number 1100007003 at II.A.36). Thus, it appears these boilers burn primarily natural gas, but it is not clear. For the units identified in the Title V permit as the "Grandfathered boilers," the permit indicates that these units are fueled by natural gas, diesel, and other fuels and, unlike the "Aggregated Boiler Group" and the "NSPS Boilers," the permit does not describe the "Grandfathered boilers" as natural gas fired boilers(189, Hill Air Face Base-Main Base Title V Permit Number 1100007003 at II.A.33 & 34). Distinguishing the primary type of fuel burned in typical operation is an important part of evaluating BACT for an emissions unit. UDAQ must consider as a BACT measure limiting the type of fuel burned to natural gas which is much lower in PM2.5 and precursor emissions than diesel, due to little to no particulate or SO2 emitted from natural gas-fired units. While the HAFB BACT submittal states that limiting the use of fuels to only natural gas is not technically feasible due to Air Force readiment requirements, HAFB indicates that "it is feasible to limit the use of alternative fuels to the minimum required to sustain the mission of the facility and periods of natural gas curtailment."(190, April 25, 2017 Hill Air Force Base BACT Submittal at 3-6.) Yet, HAFB's BACT submittal did not contain specific information on the actual use of diesel and other fuels compared to natural gas at the HAFB generators, nor did HAFB propose a limit on the use of diesel and other fuels. Given that HAFB indicated it could limit the amount of alternative fuels, *UDAQ must consider imposing a numerical limit on total amount of fuels fired for fuels other than pipeline natural gas in the generators. UDAQ also must quantify whether such a limit equates to a reduction from past practice or if it would simply equate to a cap on future practices.*

Response to Comment 1:
The following response assumes the comments in the paragraph above where "generator" was used actually meant to refer to "boiler" as noted by the repeated reference throughout the paragraph to boilers from the HAFB Title V permit.

All boilers at Hill AFB are fired on natural gas as a primary fuel (excluding the 25 MMBtu/hr used oil boiler in building 1703) and alternative secondary fuels. The alternative secondary fuels are; diesel, # 2 fuel oil, JP-4, JP-5, JP-6, JP-8, JP-10, and Jet A. Hill AFB must be able to operate during natural gas curtailment which requires boilers to operate on a secondary fuel. Due to the nature of national security and the inherent unpredictability of mission and readiness requirements (e.g. conflict, war, acts of terrorism), it is not technically feasible for the Air Force to take a limit on the quantity of alternative fuel consumption. Hill AFB is limited to situations (i.e. readiness requirements, natural gas curtailment) where it is allowable for alternate fuels to be consumed. During these situations, Hill AFB limits the use of the alternative fuels to the minimum required to sustain the mission of the facility as already noted in the Hill AFB Title V permit.

BACT for Generators When Firing Diesel

Comment 2:

The HAFB BACT submittal does not discuss BACT for SO2 when the generators are firing diesel fuel. UDAQ's BACT evaluation report does list several measures regarding limiting hours of operation and use of good combustion practices as well as ultra-low sulfur fuel. UDAQ claims these measures represent BACT and are being implemented by HAFB (191, July 1, 2018 UDAQ PM2.5 SIP Evaluation Report: Department of the Air Force, Hill Air Force Base at pdf pages 21 and23). However, a review of the HAFB Title V permit indicates that only the NSPS Compression Ignition Internal Combustion Engine (Unit # 55) is limited to ultra-low sulfur diesel (<0.0015% sulfur content), (192, HAFB Title V Permit Number 1100007003 at 114 and 115 (Condition II.B.43.b). Other than the specific requirement for diesel at Unit #55, the sulfur content of diesel fuels burned is allowed to be much higher. Specifically, Condition II.B.9.b. of the HAFB Title V permit limits sulfur content of diesel fuel to no greater than 0.5% by weight, which is more than 300 times higher than the sulfur content specifications for ultra-low sulfur diesel fuel. At the minimum, *UDAQ must require all diesel used at HAFB to meet ultra-low sulfur diesel requirements of less than 0.0015% sulfur content by weight.*

Response to Comment 2:

Hill AFB has generators that are subject to NSPS 40 CFR 60 Subpart IIII that requires Hill AFB to operate on ultra-low sulfur diesel fuel (0.0015% sulfur content by weight). Hill AFB only purchase and receive ultra-low sulfur diesel fuel for use in all generators including those not subject to the NSPS 40 CFR 60 Subpart IIII.

Boilers

Comment 3:

In addition, all generators that fire diesel should, at the minimum, be subject to annual tune-up requirements to control NOx and VOC emissions. The requirements in 40 C.F.R. Part 63, Subpart DDDDD for annual boiler tune-ups could readily be required on all HAFB generators. Boiler tune-ups can lower NOx and PM2.5 emission rates, among other pollutants, and more frequent tune-ups can more consistently ensure lower emission rates. Thus, *UDAQ and HAFB must at the minimum consider annual tune-ups for all generators that fire diesel fuel.*

Response to Comment 3:

The following response assumes the comments in the paragraph above where "generator" was used actually meant to refer to "boiler". 40 CFR 63 Subpart DDDDD is a requirement on boilers at HAP Major Sources. The commenters repeated reference, throughout the paragraph, to generators fired on diesel fuel should refer to boilers fired on diesel fuel.

All boilers at Hill AFB are fired on natural gas as a primary fuel (excluding the 25 MMBtu/hr used oil boiler in building 1703) and alternative secondary fuels. The alternative secondary fuels are; diesel, # 2 fuel oil, JP-4, JP-5, JP-6, JP-8, JP-10, and Jet A. Hill AFB must be able to operate during natural gas curtailment which requires boilers to operate on a secondary fuel.

The following response assumes the comments in the paragraph above where "boilers" was used actually meant to refer to "generator".

40 CFR 63 Subpart DDDDD provides tune-up requirements for boilers at Major HAP sources and not generators. All generators at Hill AFB are either subject to NESHAP standards under 40 CFR 63 Subpart ZZZZ or NSPS standards under 40 CFR 60 Subpart IIII or JJJJ. The NESHAP standard includes maintenance requirements that are specific to generators including changing oil and filters every 500 hours of operation or annually whichever comes first, inspecting air cleaners every 1000 hours or annually whichever comes first, and inspecting all hoses and belts every 500 hours of operation or annually whichever comes first. 40 CFR 63 Subpart ZZZZ also requires the permittee to maintain and operate the generators including associated air pollution control equipment and monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions. 40 CFR 60 Subpart IIII for generators requires that the permittee maintain and operate the generators to achieve the emission standards over the life of the engine. Specifically, the owner must operate and maintain the generators and control device according to manufacturer's emission-related instruction and only change those emission related settings that are permitted by the manufacturer. Both the NESHAP and NSPS maintenance standards are specific to generators and more stringent than just an annual tune-up. These generator-specific requirements are already included in the Hill AFB Title V permit (Permit Number: 1100007003 at Condition II.B.52).

Comment 4:
UDAQ listed good combustion practices, proper equipment operation and maintenance, and use of ultra-low sulfur fuel as being selected as BACT but did not impose any new requirements on the diesel-fired units at HAFB, claiming that "[i]mplementation is complete" at HAFB (193, July 1, 2018 UDAQ PM2.5 SIP Evaluation Report: Department of the Air Force, Hill Air Force Base at pdf page 23). As demonstrated above, there are additional requirements that UDAQ should impose on the diesel-fired units to ensure complete implementation of the measures UDAQ found to meet BACT, including the requirement for all units to <u>*use ultra-low sulfur diesel and the requirement for all units to be subject to annual boiler tune-up requirements.*</u>

Response to Comment 4:
The following response assumes the comment in the paragraph above is referring to boilers.

All boilers at Hill AFB are fired on natural gas as a primary fuel (excluding the 25 MMBtu/hr used oil boiler in building 1703) and alternative secondary fuels. The alternative secondary fuels are; diesel, # 2 fuel oil, JP-4, JP-5, JP-6, JP-8, JP-10, and Jet A. Hill AFB must be able to operate the boilers during natural gas curtailment or if natural gas is not available (conflict, war, acts of terrorism); this requires Hill AFB to have boilers with the ability to operate on a secondary fuel with no limits.

40 CFR 63 Subpart DDDDD specifies tune-up requirements for boilers at Major HAP sources. Hill AFB operates over 90 boilers and heaters that are subject to the tune-up requirements of 40 CFR 63 Subpart DDDDD. The remaining boiler and heaters are mainly small comfort or space heating units and water heaters less than 120 gallons or less than 1.6 MMBtu/hr capacity. The small boilers are exempt from the requirements of 40 CFR 63 Subpart DDDDD as well as the requirement to obtain an approval order, but are covered under UAC R307-230-3 "NO_X Emission Limits for Natural Gas-Fired Water Heaters" and do not warrant further requirements.

If the commenter is referring to generators in the above comment the following is the response.

All generators at Hill AFB are either subject to NESHAP standards under 40 CFR 63 Subpart ZZZZ or NSPS standards under 40 CFR 60 Subpart IIII or JJJJ. The NESHAP standard includes maintenance requirements that are specific to generators including changing oil and filters every 500 hours of operation or annually whichever comes first, inspecting air cleaners every 1000 hours or annually whichever comes first, and inspecting all hoses and belts every 500 hours of operation or annually whichever comes first. 40 CFR 63 Subpart ZZZZ also requires the permittee to maintain and operate the generators including associated air pollution control equipment and monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions. 40 CFR 60 Subpart IIII for generators requires that the permittee maintain and operate the generators to achieve the emission standards over the life of the engine. Specifically, the owner must operate and maintain the generators and control device according to manufacturer's emission-related instruction and only change those emission related settings that are permitted by the manufacturer. Both the NESHAP and NSPS maintenance standards are specific to generators and more stringent than just an annual tune-up. These generator-specific requirements are already included in the Hill AFB Title V permit.

Hill AFB has generators that are subject to NSPS 40 CFR 60 Subpart IIII that requires Hill AFB to operate on ultra-low sulfur diesel fuel (0.0015% sulfur content by weight). Hill AFB only purchase and receive ultra-low sulfur diesel fuel for use in all generators including those not subject to the NSPS 40 CFR 60 Subpart IIII.

BACT for Gas-Fired Generators

Comment 5:
At the minimum, all natural gas-fired boilers should be subject to the annual tune-up requirements in 40 C.F.R. Part 63, Subpart DDDDD as part of UDAQ's BACT determination. Boiler tune-ups can lower NOx emission rates from gas-fired boilers, among other pollutants, and more frequent tune-ups can more consistently ensure lower emission rates. Thus, *<u>UDAQ and HAFB must at the minimum consider annual tune-ups for all gas-fired boilers, regardless of whether a boiler is subject to Subpart DDDDD.</u>*

Response to Comment 5:
Hill AFB has over 90 boilers and heaters that are subject to the tune-up requirements of 40 CFR 63 Subpart DDDDD. The remaining boiler and heaters are mainly small comfort or space heating units and water heaters less than 120 gallons or less than 1.6 MMBtu/hr capacity. The units are exempt from the requirements of 40 CFR 63 Subpart DDDDD as well as the requirement to obtain an approval order. The EPA estimated in the development of 40 CFR 63 Subpart DDDDD [see "Regulatory Impact Results for the Reconsideration Final Rule for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources", December 19, 2012] that tune-ups would result in a 1% reduction in the amount of fuel consumed. The small boilers are exempt from the requirements of 40 CFR 63 Subpart DDDDD as well as the requirement to obtain an approval order, but are covered under UAC R307-230-3 "NOX Emission Limits for Natural Gas-Fired Water Heaters" and do not warrant further requirements.

Comment 6:
With respect to additional measures to reduce NOx from the gas-fired generators, HAFB stated that there is not sufficient space in the buildings that house the generators to retrofit the generators with ultra-low NOx burners (194, August 18, 2017 HAFB BACT Addendum, at page 3 and Attachment 1). With respect to selective catalytic reduction, HAFB said it requires exhaust gas temperatures in the range of 500 to 1,200 degrees Fahrenheit and that it is above the "designed exhaust temperature of the existing boilers at Hill AFB."(195, Id. at page 3). While the HAFB BACT Addendum cites to a Cleaver Brooks 2010 statement for this claim (196, Id), Cleaver Brooks did not indicate that SCR was technically infeasible in its letter to HAFB in Attachment 1 of the HAFB BACT Addendum. Instead, Cleaver Brooks indicated that the SCR option "would only apply to the larger boilers (40-60 MMBtu)." (197, Id., Attachment 1 at 2). There are at least nine generators sized within the 40-60 MMBtu/hour range at HAFB for which SCR could thus be considered as BACT. Further, HAFB is incorrect in stating that SCR "requires" flue gas temperatures in the range of 500 to 1,200 degrees Fahrenheit. Instead, that temperature range reflects typical conditions for SCR, but SCR can remove NOx at lower temperatures down to 300 degrees

Fahrenheit (198, Pritchard, Scot G., et al., SCR Catalyst Performance under Severe Operation Conditions, at 3). It also must be noted that it is not clear what HAFB means by the SCR temperature window being above the "designed" exhaust temperatures of the existing boilers. Because these generators are able to utilize different fuels, it is not clear what design temperature HAFB is referring to (i.e., is the design temperature reflective of design with a certain type of fuel?). Given the various types of fuel that these boilers were designed to burn, it is more important to know the actual flue gas temperatures of the generators at HAFB to determine whether or not SCR could be successfully used. There also may be lower temperature SCR catalysts available (199, See, e.g., Tang, Xialong, Low temperature selective catalytic reduction of NOx with NH3 over amorphous MnOx catalysts prepared by three methods). For all of these reasons, *HAFB's BACT analysis is flawed and incomplete for SCR. In its BACT evaluation, UDAQ claimed that SCR was not technically feasible due to current boiler limitations and spacing, but space limitations were not the primary reason identified by HAFB for discounting SCR* (200, July 1, 2018 UDAQ PM2.5 SIP Evaluation Report: Department of the Air Force, Hill Air Force Base at pdf page 10). *UDAQ must require additional analysis of SCR, especially given that Cleaver Brooks indicated that SCR was technically feasible for the larger boilers in the 40-60 MMBtu/hour range* (201, August 18, 2017 HAFB BACT Addendum, at Attachment 1). Further, *UDAQ must provide documentation for its claim that installation of SCR is not technically feasible at any HAFB boiler due to space constraints*.

Response to Comment 6:
Hill AFB has committed to replace or make inoperable all boilers manufactured before January 1, 1989 equal to or greater than 30 MMBtu/hr by December 31, 2024. Hill AFB has no other boilers on site that exceed 40 MMBtu/hr that is not being made inoperable or replaced. Therefore, no additional analysis for SCR is required for boilers that are being made inoperable or replaced.

Comment 7:
HAFB's BACT Addendum also indicates that "[s]everal projects are under consideration for removing and replacing boilers at various locations" and that HAFB has made funding requests for the replacement boilers to be equipped with ultra-low NOx burners (202, Id. at page 8). HAFB seems to indicate these projects are "currently underway" with the main issue being the timeline for completion (203, Id). The fact that the timeline for completion is not known should not justify elimination of boiler replacement as a NOx BACT control option. The definition of best available control measures includes any technologically and economically feasible control measure that can be implemented in whole or in part within 4 years after reclassification of a nonattainment area from moderate to serious. 40 C.F.R. 51.1000. As long as a boiler replacement program could be partially implemented by June 9, 2021, it should be considered as a BACT measure. *While HAFB appears to have claimed that boiler replacement is not economically feasible, the fact that they are in the process of doing so indicates that it is economically feasible for HAFB (and maybe is even warranted due to the age of the boilers HAFB is replacing). Further, if UDAQ requires boiler replacement as a BACT measure for its nonattainment plan, then HAFB would have that SIP requirement to put before Congress for budgetary approval.*

Response to Comment 7:
Hill AFB has committed to UDAQ that the following boilers will either be made inoperable or replaced with boilers determined to meet BACT by December 31, 2024; (2) 87.5 MMBtu/hr boilers in building 260, (2) 80 MMBtu/hr boilers in building 260, 60.0 MMBtu/hr boiler in building 1286, (3) 60.0 MMBtu/hr boilers in building 825, (4)50.0 MMBtu/hr boilers in building 260, and (2)40.0 MMBtu/hr boilers in building 1286. The removal of the 14 boilers requires Hill AFB to perform extensive planning for budgetary demands, base steam demand and building space requirements while taking into consideration base function.

Comment 8:

UDAQ has claimed that ultra-low NOx burners are not technically feasible to install on existing boilers due to space limitations, but UDAQ did not evaluate the replacement of the boilers with new boilers with ultra-low NOx burners as a BACT measure (204, July 1, 2018 UDAQ PM2.5 SIP Evaluation Report: Department of the Air Force, Hill Air Force Base at pdf page 9). *UDAQ must conduct such an analysis. At the minimum, UDAQ should identify those boilers which HAFB is planning to replace with new boilers with ultra-low NOx burners and specifically require such replacements as a BACT control measure.*

Response to Comment 8:
Hill AFB has committed to UDAQ the following boilers will either be inoperable or replaced with appropriate or 9 ppm NO_x boilers by December 31, 2024; (2) 87.5 MMBtu/hr boilers in building 260, (2) 80 MMBtu/hr boilers in building 260, 60.0 MMBtu/hr boiler in building 1286, (3) 60.0 MMBtu/hr boilers in building 825, (4)50.0 MMBtu/hr boilers in building 260, and (2)40.0 MMBtu/hr boilers in building 1286. The removal of the 14 boilers requires Hill AFB to perform extensive planning for budgetary demands, base steam demand and building space requirements while taking into consideration Base function. All replacement boilers will be required to meet BACT.

H-64[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, Utah Physicians for a Healthy Environment, and Heal Utah]: Review of BACT Analyses for Compass Minerals *(see VIII. Technical Report. August 14, 2018)*

Response to H-64:
General Comments 1 - 7:

Comment 1 - Compass assumed only a 20-year life in determining the annualized costs of control. At the minimum, a 30-year life should be assumed. UDAQ should assume a more appropriate and longer lifetime of controls which will reduce the annualized costs and may make one or more of these controls more cost effective.

UDAQ Response: UDAQ disagrees with the commenter. The lifespan of any particular control can vary from site to site as well as equipment to equipment on a particular site. Given the caustic nature of materials being processed on site at Compass Minerals a 20-year life span was assumed and is line with the industries average. No changes were made to the TSD or Part H limits as a result of this comment.

Comment 2 - Compass' BACT analysis for fugitive emissions has several flaws. First, the BACT analysis does not provide calculations of current actual and potential emissions for fugitive emissions sources, and the BACT analysis fails to adequately document how emissions were determined.

UDAQ Response: As correctly stated by the commenter, the source did not provide calculations of current actual and potential emissions for fugitive emission sources as part of the May 25, 2017 submittal or in DAQ-2018-007703. Therefore, UDAQ cannot present a BACT limit as part of the Emission Limits and Operating Practices of Section IX, Part H.e for fugitive emission sources at this time. UDAQ is requesting the Board to approve an additional public comment period on Part H of the serious $PM_{2.5}$ SIP. UDAQ will work with the source to determine BACT for fugitive $PM_{2.5}$ emission sources. UDAQ expects to complete the analysis and determine BACT prior to the start of the additional comment period, that is expected to begin November 1, 2018.

Comment 3 - Compass should have provided the emissions calculations for these (fugitive) sources, providing the amounts of materials handled. Further, it is not clear what silt content was assumed for the emission factors. In addition, Compass provided no basis for the assumed 90% control efficiency for moist salt emissions, did not identify the moisture content of moist salt, and did not identify the amount of salt considered to be moist salt versus the amount of salt considered to be dry salt. Compass should have more clearly spelled out its emissions calculations for these and other fugitive emission sources, so it can be ascertained whether Compass accurately calculated emissions from these sources.

UDAQ Response: As correctly stated by the commenter, the source did not provide calculations of current actual and potential emissions for fugitive emission sources as part of the May 25, 2017 submittal or in DAQ-2018-007703. Therefore, UDAQ cannot present a BACT limit as part of the Emission Limits and Operating Practices of Section IX, Part H.e for fugitive emission sources at this time. UDAQ is requesting the Board to approve an additional public comment period on Part H of the serious $PM_{2.5}$ SIP. UDAQ will work with the source to determine BACT for fugitive $PM_{2.5}$ emission sources. UDAQ expects to complete the analysis and determine BACT prior to the start of the additional comment period, that is expected to begin November 1, 2018.

Comment 4 - In addition, the emissions assumed for calculating emission reductions from fugitive dust sources, in the BACT cost effectiveness analyses, do not seem to correlate with the allowable emissions calculated and are often times lower. Compass indicates that it assumed allowable emissions for Item Nos. 1.07 and 2.11, but the assumed emissions for the cost analyses for each emissions group are much lower than the assumed allowable emissions identified in Attachment 2 of Compass' BACT submittal.

UDAQ Response: UDAQ has recognized the discrepancies between the calculated emissions and allowable emissions, and has modified the Part H limits to correspond to the limits based on newly submitted calculated emissions, stack tests, or control equipment vendor guarantees. These new limits are listed below in Table 1.

Table 1 – New proposed Part H Limits

	Nox		VOC	PM 2.5 (F + C)	PM2.5 (F + C)
Equipment	Rate (lbs/hr)	Conc. (ppm)	Rate (lb/hr)	Rate (Lb/hr)	Conc. (grains/dscf)
AH-500				1.61	0.01
AH-502 #2 Stack				0.74	0.04
D-501 & AH-513 #4 Stack				1.49	0.0114
BH-001				0.37	0.01
BH-002				0.47	0.01
BH-501				1.15	0.01
BH-502				0.06	0.0053
BH-503				0.23	0.01
BH-505				0.12	0.01
BH-008				4.25	0.01
AH-1555				0.39	0.01
D-1400 & BH-1400				2.78	0.02
AH-692 (MP WS)				0.10	0.01
BH-1516				0.22	0.01
MgCl Evaporators (4 stacks)			6.18		
Boiler #1	1.3	9			
Boiler #2	1.3	9			

*F denotes filterable limit
*C denotes condensable limit

Comment 5 - Not only did Compass assume a much lower baseline in the BACT cost effectiveness analyses for Items # 1.07 and 2.11, but Compass also subdivided these fugitive dust sources and the potential BACT controls (i.e., full enclosures with and without ducting to air pollution control equipment) into subgroupings (i.e., 1.07a, 1.07b, 1.07c) without providing any explanation or diagrams explaining why these emissions subgroups could not be included in one enclosure which could greatly reduce the costs of an enclosure and ducting to air pollution controls. Both Item 1.07 and Item 2.11 are already in separate subgroups of the same source type (i.e., “fugitive emissions from outdoor uncaptured material handling”), which was presumably done based on location of the fugitive dust sources at the plant site. Without any further explanation, it does not seem justified to break these sources up into smaller subgroups. Had Compass grouped each of these subgroups together for the cost of the enclosure, assumed a 30-year (or greater) life of the enclosure, and assumed allowable emissions that were properly calculated, the use of an enclosure and routing to air pollution controls could be quite cost effective for reducing fugitive PM2.5 emissions from these and other similar sources at the Compass facility.

UDAQ Response: UDAQ acknowledges the subdivision of material handling sources (#1.07) and the SOP plant compaction building (#2.11) that was done by Compass Minerals. This subdivision was performed to better reflect the feasibility of controls. The operational areas that these items encompass are quite large and by breaking them into smaller sections by location, as was done, they were actually able to feasibly consider enclosures; whereas had the areas not been subdivided the feasibility of enclosing such a large space becomes difficult if not impossible. Though this subdivision also reduced the emissions associated with enclosures at any given location rather than looking at emissions as a whole, it was necessary to even progress to the point where economics could play a role in the BACT decision making process. No changes were made to the TSD or Part H limits as a result of this comment.

Comment 6 - If UDAQ and Compass are relying on the fugitive dust plan to meet BACT as Compass has proposed, that plan must be made publicly available for review and comment.

UDAQ Response: Compass Minerals, has an active Fugitive Dust Control Plan (FDCP) that was issued to Great Salt Lake Minerals on April 19, 2012. The FDCP is publically available through the EZ-Search option of the divisions web page, see document DAQ-2012-004820; this document was not specifically included with the TSD as it is always available for viewing. No changes were made to the TSD or Part H limits as a result of this comment.

Comment 7 - UDAQ's BACT analysis for fugitive dust emissions does not take any of the above analysis into consideration because UDAQ did not conduct a site-specific evaluation of BACT for fugitive emissions at Compass Minerals. Instead, UDAQ addressed various facility's fugitive dust sources in its "BACT for Small Sources" document. The analysis of fugitive dust control in the "BACT for Small Sources" document is very general and does not constitute a case-by-case analysis of BACT. UDAQ must instead evaluate BACT for fugitive emissions from Compass Minerals based on a case-by-case source specific analysis of BACT which properly addresses the deficiencies in Compass' BACT analyses discussed above.

UDAQ Response: UDAQ disagrees with this comment. The "BACT for Small Sources" document was intended to address the technical and economic feasibility of emission sources that applied to various industries across the Wasatch Front. The reference to that document merely points to the fact that the analysis was done, and is comparable, to other industries with fugitive emissions from a similar process or piece of equipment, and still constitutes a case-by-case analysis. No changes were made to the TSD or Part H limits as a result of this comment.

H-65[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, Utah Physicians for a Healthy Environment and Heal Utah]: Review of BACT Analyses for Geneva Nitrogen *(see IX. Technical Report. August 14, 2018)*

<u>General Comments:</u>
It does not appear that UDAQ has done its own BACT evaluation for Geneva Nitrogen. Based on statements made at the August 1, 2018 information meeting, it appears UDAQ did not conduct a BACT analysis for Geneva Nitrogen because it reduced emissions below major source levels. UDAQ must explain in detail why it excluded Geneva Nitrogen from a BACT analysis.
If the plant reduced emissions below the 70 ton per year major source threshold, that would not exempt UDAQ from evaluating BACT for the facility. BACM including BACT must be evaluated for all sources in the Utah serious PM2.5 nonattainment areas. Given that the company submitted a BACT analysis, it must be considered to be a major source of PM2.5 or PM2.5 precursors. Below we provide comments on the company's submitted BACT analysis.

Geneva Nitrogen LLC manufactures solid ammonium nitrate in a three step process:

1. Nitric acid production
2. Ammonium nitrate solution production
3. Solid ammonium nitrate production.

Geneva Nitrogen states that the prill tower emissions of PM10 and PM2.5 are uncontrolled. Geneva Nitrogen also states that the current wet scrubbing system used during the ammonium nitrate solidification process is not considered to be BACT for the process. Geneva Nitrogen then states as follows:

a. Abandoning the existing wet scrubbers and ducting the rotating drum air streams directly through a common mist elimination module would remove a large majority of the ultra-fine particulate matter currently emitted in the wet scrubber exhaust. The PM10/2.5 emissions (fines) would be captured, placed in to solution, and recycled back into the AN process. This would meet or exceed the Best Available Control Technology requirement.

b. By retrofitting the existing prill tower with an air duct, the tower-exhaust could be brought to ground level and pulled through a mist elimination module designed to eliminate a large majority of the ultra-fine particulate matter. The PM10/2.5 emissions (fines) would be captures, placed into solution, and recycled back into the AN process. This would meet or exceed the Best Available Control Technology requirement.

August 2017 Geneva Nitrogen BACT Addendum at 26.

Despite admitting that the prill tower is not equipped with BACT, and that technology exists that meets BACT, Geneva Nitrogen dismissed routing the rotating drum air streams and the prill tower exhaust through a common mist elimination module. Geneva Nitrogen claimed these options would be "very expensive." However, if other similar sources have installed the same controls, then Geneva Nitrogen would have to demonstrate that unusual circumstances exist at its facility that would prevent the successful implementation of that control as BACT and/or which distinguish it from other sources which have implemented such controls.

Geneva Nitrogen also indicated that this control option was "likely physically infeasible in the case of ducting the existing prill tower discharge (220ft) to ground level due to load requirements on the tower structure built in 1957" and that it "would most likely also require replacement of the entire prill tower structure." UDAQ must require Geneva to investigate this control further, to determine and document whether it is feasible or not to duct the existing prill tower discharge to the ground level. If the ducting could be done with a new prill tower structure, that alone is not a reason to eliminate this control option. Instead, the costs for constructing a new prill tower to replace the 60-year old existing prill tower can be determined and considered in a cost effectiveness analysis. Given that the existing prill tower has been operating for 60 years, such a cost analysis should consider a similar lifetime for a new prill tower. Even if the cost of building a new prill tower was not reasonable, Geneva Nitrogen must still be required to evaluate the cost effectiveness of ducting the rotating drum air streams directly through a common mist elimination module.

Last, Geneva Nitrogen found these controls technically infeasible because, "[e]ven if physically feasible[,] initial engineering estimates indicate a mist eliminator cannot be installed and tested prior to the December 31, 2019 deadline." December 31, 2019 is the initial attainment date for the Salt Lake and Provo serious PM2.5 nonattainment areas. While, optimally, BACT controls should be implemented by December of 2019, there is nothing in the definition of BACT that allows a source to consider a control as not technically feasible if it cannot be implemented until after December 2019. Moreover, as long as a boiler replacement program could be partially or fully implemented by June 9, 2021 (i.e., four years after the effective date of the redesignation of the Salt Lake and Provo PM2.5 nonattainment area from moderate to serious), it should be considered as a BACT measure. According to Geneva Nitrogen's BACT Addendum, this control could be implemented by 2021.

Geneva Nitrogen did provide cost information for this control in its 2017 BACT Addendum, although there is limited documentation for its cost estimate. Geneva Nitrogen provided an annualized cost estimate of the mist elimination system to be $717,667 per year, assumed only 70% PM2.5 control ("[a]bsent adequate time to complete a detailed engineering study on this project"), and determined the cost effectiveness was $7,900/ton. It does not appear that Geneva Nitrogen took into account the reduction in ammonia emissions from this control as well, which would have made the control more cost effective. However, even with these costs (which are not significantly unreasonable), the fact is that this control has been required on a similar source, i.e., El Dorado Chemical in Arkansas. If a similar source has had to install a particular control to meet BACT, then that control is also considered BACT for similar sources absent unusual circumstances. Geneva Nitrogen did not identify any unusual circumstances to eliminate this control from its BACT analyses for the rotating drum air streams and the prill tower exhaust.

For all of these reasons, Geneva Nitrogen's BACT analysis is flawed and incomplete. UDAQ must require Geneva Nitrogen to update the analysis with more documented support for its calculated cost effectiveness. Further, absent unusual circumstances at Geneva Nitrogen, it seems the mist eliminator system should be required as BACT for the rotating drum air streams and the prill tower exhaust given that the same control has been required as BACT for another similar source. UDAQ must consider these issues in its own BACT analysis for Geneva Nitrogen.

Response to H-65: Geneva Nitrogen has ceased operations of ammonium nitrate production. An Approval Order modification (DAQE-AN108250007-18) was issued on April 24, 2018 for shut down and all production equipment, except the boiler, will be decommissioned. The boiler will remain operational to support decommissioning activities. The AO reclassifies this source as a minor source and allows the boiler to operate until the decommissioning activities are complete.

Additionally, this source is located in Utah County and is not considered a Part H source of the Salt Lake PM2.5 Serious Nonattainment area and therefore a response to this comment is not applicable.

H-66[submitted by Western Resource Advocates, Utah Chapter of Sierra Club, Utah Physicians for a Healthy Environment, and Heal Utah]: Review of BACT Analyses for Proctor & Gamble *(see X. Technical Report. August 14, 2018)*

General Comments:

Response to H-66:

Comment 1:
Proctor & Gamble owns and operates a paper, assembled paper products, and manufacturing process with two separate product lines: a paper process line and an assembled paper products line. The company recently obtained a construction permit which authorized the construction of additional production lines including the addition of two 50 MMBtu/hour boilers for process steam, comfort heating, cooling water, and back-up power (228, April 2017 Procter and Gamble Paper Products BACM/BACT Analysis at 2-1 to 2-2. See also Approval Order DAQE-AN141070009-16). *It is not clear whether those boilers have been constructed yet, as UDAQ's BACT Evaluation Report has statements indicating that the units have not yet been constructed as well as statements that the units have been constructed (229, July 1, 2018 UDAQ's PM2.5 SIP Evaluation Report: Proctor and Gamble Paper Products Company, at pdf page 5 ("[t]he boilers will be fueled by natural gas...") and pdf page 17 which implies the two 50 MMBtu/hour boilers already exist).* The boilers had not been installed at the time of Proctor & Gamble's April 2017 BACT Analysis submittal to UDAQ (230, April 2017 Procter and Gamble Paper Products BACM/BACT Analysis at 3-19). The comments below focus on NOx BACT for these two new boilers.

Response to Comment 1:
The Utility Boilers that were permitted to commence construction on December 14, 2017. Proctor & Gamble has 18 months to construct the two boilers or notify the Director of new construction timeline (DAQE-AN141070009-18, Condition II.B.1.b).

Comment 2:
Proctor & Gamble presented a NOx BACT analysis for the new 50 MMBtu/hour boilers in its April 2017 submittal (231, Id. at 3-22 to 3-24). The company found that SCR was technically feasible for the new 50 MMBtu/hour boilers, but claimed that SCR with the planned ultra-low NOx burners would not be economically reasonable (232, Id. at 3-22). The details of their cost analysis is purportedly in Appendix A of their April 2017 BACT submittal, but Appendix A is not available on UDAQ's website nor was Appendix A included in UDAQ's BACT Evaluation (233, Indeed, only the cover page for Appendix A was included at the end of UDAQ's July 1, 2018 BACT Evaluation Report for Proctor & Gamble). Yet, UDAQ appears to find the company's cost analysis for SCR acceptable, as UDAQ cites the same NOx cost effectiveness value of $165,250/ton as Proctor & Gamble claimed for SCR at the two new 50 MMBtu/hour boilers (234, July 1, 2018 UDAQ's PM2.5 SIP Evaluation Report: Proctor and Gamble Paper Products Company at pdf page 22; April 2017 Procter and Gamble Paper Products BACM/BACT Analysis at 3-22). *Given that the details of Proctor & Gamble's cost analysis were not included in its BACT submittal to UDAQ, the basis for UDAQ's concurrence that SCR is unreasonable for the new boilers is not justified.*

Response to Comment 2:
Boilers with SCR and ULNB systems operate at approximately 7 ppm (depending on the ideal conditions and elevation). SCR systems have a typical ammonia slip level of 2 to 10 ppm (EPA-452/F-03-032). The ammonia slip and additional handling and storing of ammonia for the operation of a SCR system are taken into consideration during the BACT analysis as environmental and energy impacts. Additionally, in comparing the feasibility of SCR technologies, consideration of elevation is required. The cost estimate presented is conservative as it does not include the impacts of elevation. For SCR systems located at higher elevations, the base SCR unit cost and balance of plant cost should be increased based on the ratio of the atmospheric pressure between sea level and the location of the system. (U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual (7th Edition), May 2016, Section 4.2, Chapter 2 (Selective Catalytic Reduction)).

Appendix A has been added to the record for public review which supports the cost effectiveness. The cost analysis was completed using EPA's cost manual and area specific utility costs (U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual (7th Edition), May 2016, Section 4.2, Chapter 2 (Selective Catalytic Reduction)).

Comment 3:
A review of the limited details on Proctor & Gamble's cost analysis shows significant flaws. First, the company assumed that SCR would reduce NOx emissions from the 10 ppm NOx emission rate achievable with ultra-low NOx burners down to 9 ppm (235, April 2017 Procter and Gamble Paper Products BACM/BACT Analysis at 3-22), which only reflects a NOx reduction of 10%. Yet, Proctor & Gamble as well as UDAQ claimed that SCR can achieve 70-90% NOx control (236, Id). Thus, Proctor & Gamble failed to evaluate cost effectiveness for SCR at the highest levels of NOx control efficiency that SCR could achieve, which would result in improperly inflated dollar per ton costs. *The BACT analysis must evaluate the maximum degree of emission reduction achievable with a pollution control.*

Response to Comment 3:

UDAQ conducted the SIP BACT analysis for the utility boilers based upon the emissions concentrations (ppmvd) and not control efficiency. Boilers with LNB typically have an NO_X emissions concentration of 30 ppmvd, while boilers with ULNB can reach a NOX emission concentration of 9 to 10 ppmvd. Boilers with ULNB and SCR can potentially achieve a NOX emissions concentration of 7 ppmvd. The Procter & Gamble utility boilers have ULNB systems and have a testing limit in the approval order at 10 ppmvd (1.80 lb/hr). The stated SCR control efficiency rate of 70 to 90 % is based upon a mass basis (lb/hr) and not a concentration (ppmvd). The cost to lower the NOX concentration from 10 ppmvd to 7 ppmvd is economically infeasible. In practice, boilers with; SCR, FGR and ULN systems operate at approximately 7 ppm (depending on the circumstance). SCR systems have a typical ammonia slip level of 2 to 10 ppm (EPA-452/F-03-032). The ammonia slip and additional handling and storing of ammonia for the operation of a SCR system are taken into consideration during the BACT analysis as environmental and energy impacts. The definition of BACT addresses environmental and energy impacts to be taken into consideration during the BACT determination. Environmental and energy impacts have no cost value when making the BACT determination (lowering NO_X by 2 ppm to add 2ppm of ammonia to the atmosphere, additional shipping, handling and heat energy needed for storing ammonia). The BACT determination involves cost per ton removed, environmental and energy impacts which concludes that FGR and ULN (9 ppm NOX) is BACT and not the maximum degree of emission reduction achieved.

Comment 4:
Second, Proctor & Gamble evaluated SCR cost effectiveness using the NOx emission rate with ultra-low NOx burners as reflective of baseline emissions for the cost analysis (237, Id). However, as discussed above, BACT is based on essentially uncontrolled emissions, calculated using a "realistic scenario of upper boundary uncontrolled emissions." (238, U.S. EPA, October 1990 New Source Review Workshop Manual, at B.37). *Proctor & Gamble should have thus evaluated the suite of controls of ultra-low NOx burners and SCR together in its BACT cost effectiveness analysis.*

Response to Comment 4:
The Procter & Gamble facility submitted a Notice of Intent dated November 24, 2015 for the Maple Project (Cleaning products) which included the two utility boilers. In the Notice of Intent, Procter & Gamble performed a BACT analysis having ULNB system being economically infeasible at a cost of \$19,188 per ton of NO_X removed. The BACT analysis for this permit action concluded that LNB at an emissions rate of 30 ppmvd @ 3% O2 was BACT. UDAQ responded that with the pending nonattainment classification status, that Procter & Gamble would be required to meet 9 ppmvd @ 3% O2 as BACT (SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT Best Available Control Technology (BACT) Guidelines, Part D: BACT Guidelines for Non-Major Polluting Facilities). Therefore, the source agreed to install ULBN systems on the utility boilers to meet the 9 ppmvd @ 3% O_2 for NO_X, so the new base line for the SIP BACT analysis would be the existing ULNB to the additional retrofit/add on control SCR and not an uncontrolled PTE to ULNB and SCR as discussed by commenter.

Comment 5:
Third, *Proctor & Gamble should have evaluated the possibility of routing the flue gas from each boiler to one SCR to save costs*. If the proximity of the boilers allows for it, this could be a significant cost saving measure and ensure the lowest NOx rates from these two new boilers.

Response to Comment 5:
Routing flue gas from each boiler to one SCR is technically feasible to design an SCR system to treat variable temperatures and flow rates from the two units. The Utility Boilers are designed to approximately follow production rates and have the ability to fire below full capacity to ensure only the heat necessary and fuel required is used, thereby reducing actual emissions. As the process needs change the firing rate of each boiler will change which results in a significant amount of variability. As the firing rate for these boilers are changed the temperature, flow rate and other key exhaust parameters will be

affected. In order for SCR to reduce emissions effectively, sufficient mixing of the ammonia reagent and the NOx emissions contained in the exhaust gas is essential. The additional variability resulting from potentially simultaneous changes in exhaust parameters from both units makes it technically infeasible to design a system which is adequately prepared to cope with the changes and ensure proper mixing and control.

Comment 6:
In summary, UDAQ must more fully investigate SCR as BACT for these two new boilers to ensure the maximum degree of NOx reduction is achieved. *UDAQ must also insure that appropriate interest rates (i.e., no higher than 7%) and lifetime of controls (i.e., 25-30 years) were assumed in the SCR cost effectiveness analysis.* Further, UDAQ must make the details of the SCR cost effectiveness analysis available to the public for review and comment. SCR has been required on similarly sized boilers, and thus UDAQ must more adequately justify any decision to not require SCR on the two new 50 MMBtu/hour boilers at the Proctor & Gamble facility.

Response to Comment 6:
The interest rates used for the BACT analysis was 7%. The lifetime of the controls was over 10 years with a \$165,250 cost per ton removed of NO_X for the installation and operation of the SCR. The life time of the controls is low at 10 years but considered the catalyst operating life of 40,000 hours (4.5 years) for natural gas fired boilers (EPA-452/F-03-032). The definition of BACT addresses environmental and energy impacts to be taken into consideration during the BACT determination. Environmental and energy impacts have no cost value when making the BACT determination (lowering NO_X by 2 ppm to add 2ppm of ammonia to the atmosphere, additional shipping, handling and heat energy needed for storing ammonia). The BACT determination involves cost per ton removed, environmental and energy impacts which concludes that FGR and ULN (9 ppm NOX) is BACT.

ITEM 6

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-063-18

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: September 20, 2018

SUBJECT: PROPOSE FOR PUBLIC COMMENT: Change in Proposed Rule R307-110-17. Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits.

On June 6, 2018, the Board proposed R307-110-17 for a 45-day public comment period. During that period, no comments were received. However, the amendments to Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits, incorporated through this rule received many comments and has been substantially changed. Therefore, staff has recommended it for an additional public comment period. Since R307-110-17 is the rule that incorporates the new amendments to Part H into the Utah rules, it is necessary to amend the rule to match a new extended rule making schedule.

If the Board recommends the amendments proposed to Part H for an additional public comment period, the change in proposed R307-110-17 will also need an additional public comment period.

Recommendation: Staff recommends the Board propose change in proposed R307-110-17 for an additional public comment period.

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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	$90,150,690	$0	$0
Other Person	$0	$0	$0
Total Fiscal Costs:	**$95,861,290**	**$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~~]January 2, 201[~~6~~]9, 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~~]2019
Notice of Continuation: January 27, 2017
Authorizing, and Implemented or Interpreted Law: 19-2-104

ITEM 7

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-064-18

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: September 20, 2018

SUBJECT: Five-Year Review: R307-361. Architectural Coatings.

Utah Code 63G-3-305 requires each agency to review and justify each of its rules within five years of a rule's original effective date or within five years of the filing of the last five-year review. This review process is not a time to revise or amend the rules, but only to verify that the rule is still necessary and allowed under state and federal law. As part of this process, we are required to identify any comments received since the last five-year review of each rule. This process is not the time to revisit those comments or to respond to them.

DAQ has completed a five-year review for R307-361. Architectural Coatings. The result of this review is found in the attached Five-Year Notice of Review and Statement of Continuation form.

Recommendation: Staff recommends that the Board continue R307-361, by approving the attached form to be filed with the Office of Administrative Rules.

R307. Environmental Quality, Air Quality.

R307-361. Architectural Coatings.

R307-361-1. Purpose.

(1) The purpose of R307-361 is to limit volatile organic compounds (VOC) emissions from architectural coatings.

(2) This rule specifies architectural coatings storage, cleanup, and labeling requirements.

R307-361-2. Applicability.

R307-361 applies to any person who supplies, sells, offers for sale, applies, or solicits the application of any architectural coating, or who manufactures, blends or repackages any architectural coating for use within Box Elder, Cache, Davis, Salt Lake, Tooele, Utah, and Weber counties.

R307-361-3. Definitions.

The following additional definitions apply only to R307-361.

"Adhesive" means any chemical substance that is applied for the purpose of bonding two surfaces together other than by mechanical means.

"Aerosol coating product" means a pressurized coating product containing pigments or resins that dispenses product ingredients by means of a propellant, and is packaged in a disposable can for hand-held application or for use in specialized equipment for ground traffic/marking applications.

"Aluminum roof coating" means a coating labeled and formulated exclusively for application to roofs and containing at least 84 grams of elemental aluminum pigment per liter of coating (at least 0.7 pounds per gallon).

"Appurtenance" means any accessory to a stationary structure coated at the site of installation, whether installed or detached, including, but not limited to, bathroom and kitchen fixtures; cabinets; concrete forms; doors; elevators; fences; hand railings; heating equipment, air conditioning equipment, and other fixed mechanical equipment or stationary tools; lampposts; partitions; pipes and piping systems; rain gutters and downspouts; stairways, fixed ladders, catwalks, and fire escapes; and window screens.

"Architectural coating" means a coating to be applied to stationary structures or their appurtenances at the site of installation, to portable buildings at the site of installation, to pavements, or to curbs.

(1) Coatings applied in shop applications or to non-stationary structures such as airplanes, ships, boats, railcars, and automobiles, and adhesives are not considered architectural coatings for the purposes of this rule.

"Basement specialty coating" means a clear or opaque coating that is labeled and formulated for application to concrete and masonary surfaces to provide a hydrostatic seal for basements and other below-grade surfaces, meeting the following criteria:

(1) Coating must be capable of withstanding at least 10 psi of hydrostatic pressure, as determined in accordance with ASTM D7088-04 and;

(2) Coating must be resistant to mold and mildew growth and must achieve a microbial growth rating of 8 or more, as determined in accordance with ASTM D3273-00 and ASTM D3274-95.

"Bitumens" means black or brown materials including, but not limited to, asphalt, tar, pitch, and asphaltite that are soluble in carbon disulfide, consist mainly of hydrocarbons, and are obtained from natural deposits or as residues from the distillation of crude petroleum or coal.

"Bituminous roof coating" means a coating that incorporates bitumens and that is labeled and formulated exclusively for roofing for the primary purpose of preventing water penetration.

"Bituminous roof primer" means a primer that incorporates bitumens and that is labeled and formulated exclusively for roofing and intended for the purpose of preparing a weathered or aged surface or improving adhesion of subsequent surface components.

"Bond breaker" means a coating labeled and formulated for application between layers of concrete to prevent a freshly poured top layer of concrete from bonding to the layer over which it is poured.

"Calcimine recoaters" means a flat solvent borne coating formulated and recommended specifically for coating calcimine-painted ceilings and other calcimine-painted substrates.

"Coating" means a material applied onto or impregnated into a substrate for protective, decorative, or functional purposes, and such materials include, but are not limited to, paints, varnishes, sealers, and stains.

"Colorant" means a concentrated pigment dispersion in water, solvent, or binder that is added to an architectural coating after packaging in sale units to produce the desired color.

"Concrete curing compound" means a coating labeled and formulated for application to freshly poured concrete to retard the evaporation of water and or harden or dustproof the surface of freshly poured concrete.

"Concrete/masonry sealer" means a clear or opaque coating that is labeled and formulated primarily for application to concrete and masonry surfaces to prevent penetration of water, provide resistance against abrasion, alkalis, acids, mildew, staining, or ultraviolet light, or harden or dustproof the surface of aged or cured concrete.

"Concrete surface retarder" means a mixture of retarding ingredients such as extender pigments, primary pigments, resin, and solvent that interact chemically with the cement to prevent hardening on the surface where the retarder is applied allowing the retarded mix of cement and sand at the surface to be washed away to create an exposed aggregate finish.

"Conjugated oil varnish" means a clear or semi-transparent wood coating, labeled as such, excluding lacquers or shellacs, based on a natural occurring conjugated vegetable oil (tung oil) and modified with other natural or synthetic resins; a minimum of 50% of the resin solids consisting of conjugated oil.

"Conversion varnish" means a clear acid coating with an alkyd or other resin blended with amino resins and supplied as a single component or two-component product.

"Department of Defense military technical data" means a specification that specifies design requirements, such as materials to be used, how a requirement is to be achieved, or how an item is to be fabricated or constructed.

"Driveway sealer" means a coating labeled and formulated for application to worn asphalt driveway surfaces to fill cracks, seal the surface to provide protection, or to restore or preserve the appearance.

"Dry fog coating" means a coating labeled and formulated only for spray application such that overspray droplets dry before subsequent contact with incidental surfaces in the vicinity of the surface coating activity.

"Faux finishing coating" means a coating labeled and formulated to meet one or more of the following criteria:

(1) A glaze or textured coating used to create artistic effects, including, but not limited to, dirt, suede, old age, smoke damage, and simulated marble and wood grain;

(2) A decorative coating used to create a metallic, iridescent, or pearlescent appearance and that contains at least 48 grams of pearlescent mica pigment or other iridescent pigment per liter of coating as applied (at least 0.4 pounds per gallon); or

(3) A decorative coating used to create a metallic appearance and that contains less than 48 grams of elemental metallic pigment per liter of coating as applied (less than 0.4 pounds per gallon); or

(4) A decorative coating used to create a metallic appearance and that contains greater than 48 grams of elemental metallic pigment per liter of coating as applied (greater than 0.4 pounds per gallon) and which requires a clear topcoat to prevent the degradation of the finish under normal use conditions; or

(5) A clear topcoat to seal and protect a faux finishing coating that meets the requirements of (1) through (4) of this definition, and these clear topcoats shall be sold and used solely as part of a faux finishing coating system.

"Fire-resistive coating" means a coating labeled and formulated to protect structural integrity by increasing the fire endurance of interior or exterior steel and other structural materials. The Fire-Resistive coating category includes sprayed fire resistive materials and intumescent fire resistive coatings that are used to bring structural materials into compliance with federal, state, and local building code requirements. The fire-resistant coatings shall be tested in accordance with ASTM E119-08.

"Flat coating" means a coating that is not defined under any other definition in this rule and that registers gloss less than 15 on an 85 degree meter or less than 5 on a 60 degree meter according to ASTM D523-89 (1999).

"Floor coating" means an opaque coating that is labeled and formulated for application to flooring, including, but not limited to, decks, porches, steps, garage floors, and other horizontal surfaces that may be subject to foot traffic.

"Form-release compound" means a coating labeled and formulated for application to a concrete form to prevent the freshly poured concrete from bonding to the form which may consist of wood, metal, or some material other than concrete.

"Graphic arts coating or sign paint" means a coating labeled and formulated for hand-application by artists using brush, airbrush, or roller techniques to indoor and outdoor signs, excluding structural components, and murals including lettering enamels, poster colors, copy blockers, and bulletin enamels.

"High-temperature coating" means a high performance coating labeled and formulated for application to substrates exposed continuously or intermittently to temperatures above 204 degrees Celsius (400 degrees Fahrenheit).

"Impacted immersion coating" means a high performance maintenance coating formulated and recommended for application to steel structures subject to immersion in turbulent, debris-laden water. These coatings are specifically resistant to high-energy impact damage by floating ice or debris.

"Industrial maintenance coating" means a high performance architectural coating, including primers, sealers, undercoaters, intermediate coats, and topcoats, formulated for application to substrates, including floors exposed to one or more of the following extreme environmental conditions:

(1) Immersion in water, wastewater, or chemical solutions (aqueous and non-aqueous solutions), or chronic exposure of interior surfaces to moisture condensation;

(2) Acute or chronic exposure to corrosive, caustic or acidic agents, or to chemicals, chemical fumes, or chemical mixtures or solutions;

(3) Frequent exposure to temperatures above 121 degrees Celsius (250 degrees Fahrenheit);

(4) Frequent heavy abrasion, including mechanical wear and frequent scrubbing with industrial solvents, cleansers, or scouring agents; or

(5) Exterior exposure of metal structures and structural components.

"Low solids coating" means a coating containing 0.12 kilogram or less of solids per liter (1 pound or less of solids per gallon) of coating material as recommended for application by the manufacturer.

"Magnesite cement coating" means a coating labeled and formulated for application to magnesite cement decking to protect the magnesite cement substrate from erosion by water.

"Manufacturer's maximum thinning recommendation" means the maximum recommendation for thinning that is indicated on the label or lid of the coating container.

"Mastic texture coating" means a coating labeled and formulated to cover holes and minor cracks and to conceal surface irregularities, and is applied in a single coat of at least 10 mils (at least 0.010 inch) dry film thickness.

"Medium density fiberboard (MDF)" means a composite wood product, panel, molding, or other building material composed of cellulosic fibers, usually wood, made by dry forming and pressing of a resinated fiber mat.

"Metallic pigmented coating" means a coating that is labeled and formulated to provide a metallic appearance and must contain at least 48 grams of elemental metallic pigment (excluding zinc) per liter of coating as applied (at least 0.4 pounds per gallon), when tested in accordance with SCAQMD Method 318-95, but does not include coatings applied to roofs, or zinc-rich primers.

"Multi-color coating" means a coating that is packaged in a single container and that is labeled and formulated to exhibits more than one color when applied in a single coat.

"Non-flat coating" means a coating that is not defined under any other definition in this rule and that registers a gloss of 15 or greater on an 85-degree meter and five or greater on a 60-degree meter according to ASTM D523-89 (1999).

"Non-flat/high-gloss coating" means a non-flat coating that registers a gloss of 70 or greater on a 60-degree meter according to ASTM D523-89 (1999).

"Nuclear coating" means a protective coating formulated and recommended to seal porous surfaces such as steel or concrete that otherwise would be subject to intrusion by radioactive materials. These coatings must be resistant to long-term cumulative radiation exposure according to ASTM Method 4082-02, relatively easy to decontaminate, and resistant to various chemicals to which the coatings are likely to be exposed according to ASTM Method D 3912-95 (2010).

"Particleboard" means a composite wood product panel, molding, or other building material composed of cellulosic material, usually wood, in the form of discrete particles, as distinguished from fibers, flakes, or strands, which are pressed together with resin.

"Pearlescent" means exhibiting various colors depending on the angles of illumination and viewing, as observed in mother-of-pearl.

"Plywood" means a panel product consisting of layers of wood veneers or composite core pressed together with resin and includes panel products made by either hot or cold pressing (with resin) veneers to a platform.

"Post-consumer coating" means a finished coatings generated by a business or consumer that have served their intended end uses, and are recovered from or otherwise diverted from the waste stream for the purpose of recycling.

"Pre-treatment wash primer" means a primer that contains a minimum of 0.5% acid, by weight, when tested in accordance with ASTM D1613-06, that is labeled and formulated for application directly to bare metal surfaces to provide corrosion resistance and to promote adhesion of subsequent topcoats.

"Primer, sealer, and undercoater" means a coating labeled and formulated to provide a firm bond between the substrate and the subsequent coatings, prevent subsequent coatings from being absorbed by the substrate, prevent harm to subsequent coatings by materials in the substrate, provide a smooth surface for the subsequent application of coatings, provide a clear finish coat to seal the substrate, or to block materials from penetrating into or leaching out of a substrate.

"Reactive penetrating sealer" means a clear or pigmented coating that is formulated for application to above-grade concrete and masonry substrates to provide protection from water and waterborne contaminants, including, but not limited to, alkalis, acids, and salts.

(1) Reactive penetrating sealers penetrate into concrete and masonry substrates and chemically react to form covalent bonds with naturally occurring minerals in the substrate.

(2) Reactive penetrating sealers line the pores of concrete and masonry substrates with a hydrophobic coating but do not form a surface film.

(3) Reactive penetrating sealers shall meet all of the following criteria:

(a) The reactive penetrating sealer must improve water repellency at least 80% after application on a concrete or masonry substrate, and this performance shall be verified on standardized test specimens in accordance with one or more of the following standards: ASTM C67-07, ASTM C97-02, or ASTM C140-06.

(b) The reactive penetrating sealer shall not reduce the water vapor transmission rate by more than 2% after application on a concrete or masonry substrate, and this performance must be verified on standardized test specimens, in accordance with ASTM E96/E96M-05.

(c) Products labeled and formulated for vehicular traffic surface chloride screening applications shall meet the performance criteria listed in the National Cooperative Highway Research Report 244 (1981).

"Reactive penetrating carbonate stone sealer" means a clear or pigmented coating that is labeled and formulated for application to above-grade carbonate stone substrates to provide protection from water and waterborne contaminants, including but not limited to, alkalis acids, and salts and that penetrates into carbonate stone substrates and chemically reacts to form covalent bonds with naturally occurring minerals in the substrate. They must meet all of the following criteria:

(1) Improve water repellency at least 80% after application on a carbonate stone substrate. This performance shall be verified on standardized test specimens, in accordance with one or more of the following standards: ASTM C67-07, ASTM C97-02, or ASTM C140-06; and

(2) Not reduce the water vapor transmission rate by more than 10% after application on a carbonate stone substrate. This performance shall be verified on standardized test specimens in accordance with one or more of the following standards: ASTM E96/E96M-05.

"Recycled coating" means an architectural coating formulated such that it contains a minimum of 50% by volume post-consumer coating, with a maximum of 50% by volume secondary industrial materials or virgin materials.

"Residential" means areas where people reside or lodge, including, but not limited to, single and multiple family dwellings, condominiums, mobile homes, apartment complexes, motels, and hotels.

"Roof coating" means a non-bituminous coating labeled and formulated for application to roofs for the primary purpose of preventing water penetration, reflecting ultraviolet light, or reflecting solar radiation.

"Rust preventative coating" means a coating that is for metal substrates only and is formulated to prevent the corrosion of metal surfaces for direct-to-metal coating or a coating intended for application over rusty, previously coated surfaces but does not include coatings that are required to be applied as a topcoat over a primer or coatings that are intended for use on wood or any other nonmetallic surface.

"Secondary industrial materials" means products or by-products of the paint manufacturing process that are of known composition and have economic value but can no longer be used for their intended purpose.

"Semitransparent coating" means a coating that contains binders and colored pigments and is formulated to change the color of the surface but not conceal the grain pattern or texture.

"Shellac" means a clear or opaque coating formulated solely with the resinous secretions of the lac beetle (Laciffer lacca) and formulated to dry by evaporation without a chemical reaction.

"Shop application" means an application of a coating to a product or a component of a product in or on the premises of a factory or a shop as part of a manufacturing, production, or repairing process (e.g., original equipment manufacturing coatings).

"Solicit" means to require for use or to specify by written or oral contract.

"Specialty primer, sealer, and undercoater" means a coating that is formulated for application to a substrate to block water-soluble stains resulting from fire damage, smoke damage, or water damage.

"Stain" means a semi-transparent or opaque coating labeled and formulated to change the color of a surface but not conceal the grain pattern or texture.

"Stone consolidant" means a coating that is labeled and formulated for application to stone substrates to repair historical structures that have been damaged by weathering or other decay mechanisms.

(1) Stone consolidants must penetrate into stone substrates to create bonds between particles and consolidate deteriorated material.

(2) Stone consolidants must be specified and used in accordance with ASTM E2167-01.

"Swimming pool coating" means a coating labeled and formulated to coat the interior of swimming pools and to resist swimming pool chemicals.

"Thermoplastic rubber coating and mastic" means a coating or mastic formulated and recommended for application to roofing or other structural surfaces that incorporates no less than 40% by weight of thermoplastic rubbers in the total resin solids and may also contain other ingredients, including, but not limited to, fillers, pigments, and modifying resins.

"Tint base" means an architectural coating to which colorant is added after packaging in sale units to produce a desired color.

"Traffic marking coating" means a coating labeled and formulated for marking and striping streets, highways, or other traffic surfaces, including, but not limited to, curbs, berms, driveways, parking lots, sidewalks, and airport runways.

"Tub and tile refinish coating" means a clear or opaque coating that is labeled and formulated exclusively for refinishing the surface of a bathtub, shower, sink, or countertop and that meets the following criteria:

(1) Has a scratch hardness of 3H or harder and a gouge hardness of 4H or harder, determined on bonderite 1000, in accordance with ASTM D3363-05;

(2) Has a weight loss of 20 milligrams or less after 1,000 cycles, determined with CS-17 wheels on bonderite 1000, in accordance with ASTM D4060-07;

(3) Withstands 1,000 hours or more of exposure with few or no #8 blisters, determined on unscribed bonderite in accordance with ASTM D4585-99, and ASTM D714-02e1; and

(4) Has an adhesion rating of 4B or better after 24 hours of recovery, determined on unscribed bonderite in accordance with ASTM D4585-99 and ASTM D3359-02.

"Veneer" means thin sheets of wood peeled or sliced from logs for use in the manufacture of wood products such as plywood, laminated veneer lumber, or other products.

"Virgin Materials" means materials that contain no post-consumer coatings or secondary industrial materials.

"VOC actual" means the weight of VOC per volume of coating and applies to coatings in the low solids coatings category and it is calculated with the following equation:

VOC Actual = (Ws - Ww - Wec)/(Vm)

Where, VOC actual = the grams of VOC per liter of coating (also known as "Material VOC");

Ws = weight of volatiles, in grams;

Ww = weight of water, in grams;

Wec = weight of exempt compounds, in grams; and

Vm = volume of coating, in liters

"VOC content" means the weight of VOC per volume of coating and is VOC regulatory for all coatings except those in the low solids category.

(1) For coatings in the low solids category, the VOC Content is VOC actual.

(2) If the coating is a multi-component product, the VOC content is VOC regulatory as mixed or catalyzed.

(3) If the coating contains silanes, siloxanes, or other ingredients that generate ethanol or other VOCs during the curing process, the VOC content must include the VOCs emitted during curing.

(4) VOC content must include maximum amount of thinning solvent recommended by the manufacturer.

"VOC regulatory" means the weight of VOC per volume of coating, less the volume of water and exempt compounds. It is calculated with the following equation:

VOC Regulatory = (Ws - Ww - Wec)/(Vm - Vw - Vec)

Where, VOC regulatory = grams of VOC per liter of coating, less water and exempt compounds (also known as "Coating VOC");

Ws = weight of volatiles, in grams;

Ww = weight of water, in grams;
Wec = weight of exempt compounds, in grams;
Vm = volume of coating, in liters;
Vw = volume of water, in liters; and
Vec = volume of exempt compounds, in liters

VOC regulatory must include maximum amount of thinning solvent recommended by the manufacturer.

"Waterproofing membrane" means a clear or opaque coating that is labeled and formulated for application to concrete and masonry surfaces to provide a seamless waterproofing membrane that prevents any penetration of liquid water into the substrate.

(1) Waterproofing membranes are intended for the following waterproofing applications: below-grade surfaces, between concrete slabs, inside tunnels, inside concrete planters, and under flooring materials.

(2) The waterproofing membrane category does not include topcoats that are included in the concrete/masonry sealer category (e.g., parking deck topcoats, pedestrian deck topcoats, etc.).

(3) Waterproofing Membranes shall:

(a) Be applied in a single coat of at least 25 mils (at least 0.025 inch) dry film thickness; and

(b) Meet or exceed the requirements contained in ASTM C836-06.

"Wood coatings" means coatings labeled and formulated for application to wood substrates only and include clear and semitransparent coatings: lacquers; varnishes; sanding sealers; penetrating oils; clear stains; wood conditioners used as undercoats; and wood sealers used as topcoats. The Wood Coatings category also includes the following opaque wood coatings: opaque lacquers, opaque sanding sealers, and opaque lacquer undercoaters but do not include clear sealers that are labeled and formulated for use on concrete/masonry surfaces or coatings intended for substrates other than wood.

"Wood preservative" means a coating labeled and formulated to protect exposed wood from decay or insect attack that is registered with the U.S. EPA under the Federal Insecticide, Fungicide, and Rodenticide Act (7 United States Code (U.S.C.) Section 136, et seq.).

"Wood substrate" means a substrate made of wood, particleboard, plywood, medium density fiberboard, rattan, wicker, bamboo, or composite products with exposed wood grain but does not include items comprised of simulated wood.

"Zinc-rich primer" means a coating that contains at least 65% metallic zinc powder or zinc dust by weight of total solids and is formulated for application to metal substrates to provide a firm bond between the substrate and subsequent applications of coatings and are intended for professional use only.

R307-361-4. Exemptions.

The coatings described in R307-361-4(1) through (3) are exempt from the requirements of R307-361.

(1) Any architectural coating that is supplied, sold, offered for sale, or manufactured for use outside of the counties in R307-361-2 or for shipment to other manufacturers for reformulation or

repackaging.

(2) Any aerosol coating product.

(3) Any architectural coating that is sold in a container with a volume of one liter (1.057 quarts) or less, including kits containing containers of different colors, types or categories of coatings and two component products and including multiple containers of one liter or less that are packaged and shipped together with no intent or requirement to ultimately be sold as one unit.

(a) The exemption in R307-361-4(3) does not include bundling of containers one liter or less, which are sold together as a unit with the intent or requirement that they be combined into one container.

(b) The exemption in R307-361-4(3) does not include packaging from which the coating cannot be applied. This exemption does include multiple containers of one liter or less that are packaged and shipped together with no intent or requirement to ultimately sell as one unit.

(4) The requirements of R307-361-5 Table 1 do not apply to operations that are exclusively covered by Department of Defense military technical data and performed by a Department of Defense contractor and or on site at installations owned and or operated by the United States Armed Forces.

R307-361-5. Standards.

(1) Except as provided in R307-361-4, no person shall manufacture, blend, or repackage, supply, sell, or offer for sale within the counties in R307-361-2; or solicit for application or apply within those counties any architectural coating with a VOC content in excess of the corresponding limit specified in Table 1.

TABLE 1

VOC Content Limit for Architectural and Industrial Maintenance Coatings

(Limits are expressed as VOC content, thinned to the manufacturer's maximum thinning recommendation, excluding any colorant added to tint bases.)

COATING CATEGORY	VOC Content Limit (grams/liter)
Flat coatings	50
Non-flat coatings	100
Non-flat/high-gloss coatings	150
Specialty Coatings	
Aluminum roofing	450
Basement Specialty Coatings	400
Bituminous Specialty Coatings	400
Bituminous roof coatings	270
Bituminous roof primers	350
Bond beakers	350
Calcimine recoaters	475
Concrete curing compounds	350

Concrete/masonary sealer	100
Concrete surface retarders	780
Conjugated oil varnish	450
Conversion varnish	725
Driveway sealers	50
Dry fog coatings	150
Faux finishing coatings	350
Fire resistive coatings	350
Floor coatings	100
Form-release compounds	250
Graphic arts coatings (sign paints)	500
High temperature coatings	420
Impacted Immersion Coatings	780
Industrial maintenance coatings	250
Low solids coatings	120
Magnesite cement coatings	450
Mastic texture coatings	100
Metallic pigmented coatings	500
Multi-color coatings	250
Nuclear coatings	450
Pre-treatment wash primers	420
Primers, sealers, and undercoaters	100
Reactive penetrating sealer	350
Reactive penetrating carbonate stone sealer	500
Recycled coatings	250
Roof coatings	250
Rust preventative coatings	250
Shellacs:	
Clear	730
Opaque	550
Specialty primers, sealers, and undercoaters	100
Stains	250
Stone consolidant	450
Swimming pool coatings	340
Thermoplastic rubber coatings and mastic	550
Traffic marking coatings	100
Tub and tile refinish	420
Waterproofing membranes	250
Wood coating	275
Wood Preservatives	350
Zinc-Rich Primer	340

(2) If a coating is recommended for use in more than one of the specialty coating categories listed in Table 1, the most restrictive (lowest) VOC content limit shall apply.

(a) This requirement applies to usage recommendations that appear anywhere on the coating container, anywhere on any label or sticker affixed to the container, or in any sales, advertising, or technical literature supplied by a manufacturer or anyone acting on their behalf.

(b) R307-361-5(2) does not apply to the following coating categories:

(i) Aluminum roof coatings
(ii) Bituminous roof primers
(iv) High temperature coatings
(v) Industrial maintenance coatings
(vi) Low-solids coatings
(vii) Metallic pigmented coatings
(viii) Pretreatment wash primers
(ix) Shellacs
(x) Specialty primers, sealers and undercoaters
(xi) Wood Coatings
(xii) Wood preservatives
(xiii) Zinc-rich primers
(xiv) Calcimine recoaters
(xv) Impacted immersion coatings
(xvi) Nuclear coatings
(xvii) Thermoplastic rubber coatings and mastic
(xviii) Concrete surface retarders
(xix) Conversion varnish

(3) Sell-through of coatings. A coating manufactured prior to January 1, 2015, may be sold, supplied, or offered for sale for up to three years after January 1, 2015.

(a) A coating manufactured before January 1, 2015, may be applied at any time.

(b) R307-361-5(3) does not apply to any coating that does not display the date or date code required by R307-361-6(1)(a).

(4) Painting practices. All architectural coating containers used when applying the contents therein to a surface directly from the container by pouring, siphoning, brushing, rolling, padding, ragging or other means, shall be closed when not in use. These architectural coating containers include, but are not limited to, drums, buckets, cans, pails, trays or other application containers. Containers of any VOC-containing materials used for thinning and cleanup shall also be closed when not in use.

(5) Thinning. No person who applies or solicits the application of any architectural coating shall apply a coating that is thinned to exceed the applicable VOC limit specified in Table 1.

(6) Rust preventative coatings. No person shall apply or solicit the application of any rust preventative coating manufactured before January 1, 2015 for industrial use, unless such a rust preventative coating complies with the industrial maintenance coating VOC limit specified in Table 1.

(7) Coatings not listed in Table 1. For any coating that does not meet any of the definitions for the specialty coatings categories listed in Table 1, the VOC content limit shall be determined by classifying the coating as a flat, non-flat, or non-flat/high gloss coating, based on its gloss, as defined in R307-361-3 and the corresponding flat, non-flat, or non-flat/high gloss coating VOC limit

in Table 1 shall apply.

R307-361-6. Container Labeling Requirements.

(1) Each manufacturer of any architectural coating subject to R307-361 shall display the information listed in R307-361-6(1)(a) through (c) on the coating container (or label) in which the coating is sold or distributed.

(a) Date Code.

(i) The date the coating was manufactured, or a date code representing the date, shall be indicated on the label, lid or bottom of the container.

(ii) If the manufacturer uses a date code for any coating, the manufacturer shall file an explanation of each code with the director upon request.

(b) Thinning Recommendations.

(i) A statement of the manufacturer's recommendation regarding thinning of the coating shall be indicated on the label or lid of the container.

(ii) This requirement does not apply to the thinning of architectural coatings with water.

(iii) If thinning of the coating prior to use is not necessary, the recommendation shall specify that the coating is to be applied without thinning.

(c) VOC Content.

(i) Each container of any coating subject to this rule shall display one of the following values, in grams of VOC per liter of coating:

(A) Maximum VOC content as determined from all potential product formulations;

(B) VOC content as determined from actual formulation data; or

(C) VOC content as determined using the test methods in R307-361-8.

(ii) If the manufacturer does not recommend thinning, the container shall display the VOC Content, as supplied.

(iii) If the manufacturer recommends thinning, the container shall display the VOC Content, including the maximum amount of thinning solvent recommended by the manufacturer.

(iv) If the coating is a multicomponent product, the container shall display the VOC content as mixed or catalyzed.

(v) If the coating contains silanes, siloxanes, or other ingredients that generate ethanol or other VOCs during the curing process, the VOC content shall include the VOCs emitted during curing.

(2) Faux finishing coatings. The labels of all clear topcoat faux finishing coatings shall prominently display the statement, "This product can only be sold or used as part of a faux finishing coating system."

(3) Industrial maintenance coatings. The label of all industrial maintenance coatings shall prominently display at least one of the following statements:

(a) "for industrial use only;"

(b) "for professional use only;" or

(c) "not for residential use" or "not intended for residential use."

(4) Rust preventative coatings. The labels of all rust preventative coatings shall prominently display the statement, "For metal substrates only."

(5) Non-flat/high-gloss coatings. The labels of all non-flat/high-gloss coatings shall prominently display the words "high gloss."

(6) Specialty primers, sealers and undercoaters. The labels of all specialty primers, sealers and undercoaters shall prominently display one or more of the following descriptions:

(a) "For blocking stains;"

(b) "For smoke-damaged substrates;"

(c) "For fire-damaged substrates;"

(d) "For water-damaged substrates;" or

(e) "For excessively chalky substrates."

(7) Reactive penetrating sealers. The labels of all reactive penetrating sealers shall prominently display the statement, "Reactive penetrating sealer."

(8) Reactive penetrating carbonate stone sealers. The labels of all reactive penetrating carbonate stone sealers shall prominently display the statement, "Reactive penetrating carbonate stone sealer."

(9) Stone consolidants. The labels of all stone consolidants shall prominently display the statement, "Stone consolidant -For professional use only."

(10) Wood coatings. The labels of all wood coatings shall prominently display the statement, "For wood substrates only."

(11) Zinc rich primers. The labels of all zinc rich primers shall prominently display one or more of the following descriptions:

(a) "For professional use only;"

(b) "For industrial use only;" or

(c) "Not for residential use" or "Not intended for residential use."

R307-361-7. Reporting Requirements.

(1) Within 180 days of written request from the director, the manufacturer shall provide the director with data concerning the distribution and sales of architectural coatings, including, but not limited to:

(a) The name and mailing address of the manufacturer;

(b) The name, address and telephone number of a contact person;

(c) The name of the coating product as it appears on the label and the applicable coating category;

(d) Whether the product is marketed for interior or exterior use or both;

(e) The number of gallons sold in counties listed in R307-361-2 in containers greater than one liter (1.057 quart) and equal to or less than one liter (1.057 quart);

(f) The VOC actual content and VOC regulatory content in grams per liter;

(i) If thinning is recommended, list the VOC actual content and VOC regulatory content after maximum recommended thinning.

(ii) If containers less than one liter have a different VOC content than containers greater than one liter, list separately.

(iii) If the coating is a multi-component product, provide the VOC content as mixed or catalyzed.

(g) The names and CAS numbers of the VOC constituents in the product;

(h) The names and CAS numbers of any compounds in the product specifically exempted from the VOC definition in R307-101;

(i) Whether the product is marketed as solvent-borne, waterborne, or 100% solids;

(j) Description of resin or binder in the product;

(k) whether the coating is a single-component or multi-component product;

(l) The density of the product in pounds per gallon;

(m) The percent by weight of: solids, all volatile materials, water, and any compounds in the product specifically exempted from the VOC definition in R307-101; and

(n) The percent by volume of: solids, water, and any compounds in the product specifically exempted from the VOC definition in R307-101.

R307-361-8. Test Methods.

(1) Determination of VOC content.

(a) For the purpose of determining compliance with the VOC content limits in Table 1, the VOC content of a coating shall be calculated by following the appropriate formula found in the definitions of VOC actual, VOC content, and VOC regulatory found in R307-361-3.

(b) The VOC content of a tint base shall be determined without colorant that is added after the tint base is manufactured.

(c) If the manufacturer does not recommend thinning, the VOC content shall be calculated for the product as supplied.

(d) If the manufacturer recommends thinning, the VOC content shall be calculated including the maximum amount of thinning solvent recommended by the manufacturer.

(e) If the coating is a multi-component product, the VOC content shall be calculated as mixed or catalyzed.

(f) The coating contains silanes, siloxanes, or other ingredients that generate ethanol or other VOC during the curing process, the VOC content shall include the VOCs emitted during curing.

(2) VOC content of coatings.

(a) To determine the VOC content of a coating, the manufacturer may use EPA Method 24, SCAQMD Method 304-91 (revised February1996), or an alternative method, formulation data, or any other reasonable means for predicting that the coating has been formulated as intended (e.g., quality assurance checks, recordkeeping).

(b) If there are any inconsistencies between the results of EPA Method 24 test and any other means for determining VOC content, the EPA Method 24 test results will govern.

(c) The exempt compounds content shall be determined by ASTM D 3960-05, SCAQMD Method 303-91 (Revised 1993), BAAQMD Method 43 (Revised 1996), or BAAQMD Method 41 (Revised 1995), as applicable.

(3) Methacrylate traffic marking coatings. Analysis of methacrylate multicomponent coatings used as traffic marking coatings shall be conducted according to a modification of EPA Method 24 (40 CFR 59, subpart D, Appendix A), which has not been approved for methacrylate multicomponent coatings used for purposes other than as traffic marking coatings or for other classes of multicomponent coatings.

(4) Flame spread index. The flame spread index of a fire-retardant coating shall be determined by ASTM E84-10, "Standard Test Method for Surface Burning Characteristics of Building Materials."

(5) Fire resistance rating. The fire resistance rating of a fire-resistive coating shall be determined by ASTM E119-08, "Standard Test Methods for Fire Tests of Building Construction and Materials."

(6) Gloss determination. The gloss of a coating shall be determined by ASTM D523-89 (1999), "Standard Test Method for Specular Gloss."

(7) Metal content of coatings. The metallic content of a coating shall be determined by SCAQMD Method 318-95, "Determination of Weight Percent Elemental Metal in Coatings by X-Ray Diffraction, SCAQMD Laboratory Methods of Analysis for Enforcement Samples."

(8) Acid content of coatings. The acid content of a coating shall be determined by ASTM D1613-06, "Standard Test Method for Acidity in Volatile Solvents and Chemical Intermediates Used in Paint, Varnish, Lacquer and Related Products."

(9) Drying times. The set-to-touch, dry-hard, dry-to-touch and dry-to-recoat times of a coating shall be determined by ASTM D1640-95 (1999), "Standard Methods for Drying, Curing, or Film Formation of Organic Coatings at Room Temperature," and the tack-free time of a quick-dry enamel coating shall be determined by the Mechanical Test Method of ASTM D1640-95.

(10) Surface chalkiness. The chalkiness of a surface shall be determined by using ASTM D4214-07, "Standard Test Methods for Evaluating the Degree of Chalking of Exterior Paint Films."

(11) Exempt compounds-siloxanes. Exempt compounds that are cyclic, branched, or linear, completely methylated siloxanes, shall be analyzed as exempt compounds by methods referenced in ASTM D 3960-05, "Standard Practice for Determining Volatile Organic Compound (VOC) Content of Paints and Related Coatings" or by BAAQMD Method 43, "Determination of Volatile Methylsiloxanes in Solvent-Based Coatings, Inks, and Related Materials," BAAQMD Manual of Procedures, Volume III, adopted November 6, 1996.

(12) Exempt compounds-parachlorobenzotrifluoride (PCBTF). The exempt compound PCBTF, shall be analyzed as an exempt compound by methods referenced in ASTM D 3960-05 "Standard Practice for Determining Volatile Organic Compound (VOC) Content of Paints and Related Coatings" or by BAAQMD Method 41, "Determination of Volatile Organic Compounds in Solvent Based Coatings and Related Materials Containing Parachlorobenzotriflouride," BAAQMD Manual of Procedures, Volume III, adopted December 20, 1955.

(13) Tub and tile refinish coating adhesion. The adhesion of tub and tile coating shall be determined by ASTM D4585-99, "Standard

Practice for Testing Water Resistance of Coatings Using Controlled Condensation" and ASTM D3359-02, "Standard Test Methods for Measuring Adhesion by Tape Test."

(14) Tub and tile refinish coating hardness. The hardness of tub and tile refinish coating shall be determined by ASTM D3363-05, "Standard Test Method for Film Hardness by Pencil Test."

(15) Tub and tile refinish coating abrasion resistance. Abrasion resistance of tub and tile refinish coating shall be analyzed by ASTM D4060-07, "Standard Test Methods for Abrasion Resistance of Organic Coatings by the Taber Abraser."

(16) Tub and tile refinish coating water resistance. Water resistance of tub and tile refinish coatings shall be determined by ASTM D4585-99, "Standard Practice for Testing Water Resistance of Coatings Using Controlled Condensation" and ASTM D714-02e1, "Standard Test Method for Evaluating Degree of Blistering of Paints."

(17) Waterproofing membrane. Waterproofing membrane shall be tested by ASTM C836-06, "Standard Specification for High Solids Content, Cold Liquid-Applied Elastomeric Waterproofing Membrane for Use with Separate Wearing Course."

(18) Reactive penetrating sealer and reactive carbonate stone sealer water repellency. Reactive penetrating sealer and reactive carbonate stone sealer water repellency shall be analyzed by ASTM C67-07, "Standard Test Methods for Sampling and Testing Brick and Structural Clay Tile;" ASTM C97-02, "Standard Test Methods for Absorption and Bulk Specific Gravity of Dimension Stone;" or ASTM C140-06, "Standard Test Methods for Sampling and Testing Concrete Masonry Units and Related Units."

(19) Reactive penetrating sealer and reactive penetrating carbonate stone sealer water vapor transmission. Reactive penetrating sealer and reactive penetrating carbonate stone sealer water vapor transmission shall be analyzed ASTM E96/E96M-05, "Standard Test Method for Water Vapor Transmission of Materials."

(20) Reactive penetrating sealer -chloride screening applications. Reactive penetrating sealers shall be analyzed by National Cooperative Highway Research Report 244 (1981), "Concrete Sealers for the Protection of Bridge Structures."

(21) Stone consolidants. Stone consolidants shall be tested by using ASTM E2167-01, "Standard Guide for Selection and Use of Stone Consolidants."

(22) Radiation resistance -nuclear coatings. The radiation resistance of a nuclear coating shall be determined by ASTM D 4082-02, "Standard Test Method for Use in Light Water Nuclear Power Plants."

(23) Chemical resistance-nuclear coatings. The chemical resistance of nuclear coatings shall be determined by ASTM D3912-95 (2001), "Standard Test Method for Chemical Resistance of Coatings Used in Light Water Nuclear Power Plants."

R307-361-9. Compliance Schedule.

Persons subject to this rule shall be in compliance by January 1, 2015.

KEY: air pollution, emission controls, architectural coatings

Date of Enactment or Last Substantive Amendment: October 31, 2013
Authorizing, and Implemented or Interpreted Law: 19-2-104(1); 19-2-101

FIVE-YEAR NOTICE OF REVIEW AND STATEMENT OF CONTINUATION

Rule Information

DAR file no:		Date filed:
State Admin Rule Filing Key:	160619	
Utah Admin. Code ref. (R no.):	R307-361	

Agency Information

1. Agency: ENVIRONMENTAL QUALITY - Air Quality

Room no.:	Fourth Floor
Building:	
Street address 1:	195 N 1950 W
Street address 2:	
City, state, zip:	SALT LAKE CITY UT 84116-3085
Mailing address 1:	PO BOX 144820
Mailing address 2:	
City, state, zip:	SALT LAKE CITY UT 84114-4820

Contact person(s):

Name:	Phone:	Fax:	E-mail:	Remove:
Thomas Gunter	801-536-4419		thomasgunter@utah.gov	

(Interested persons may inspect this filing at the above address or at DAR during business hours)

Rule Title

2. Title of rule or section (catchline):
Architectural Coatings

Rule Provisions

3. A concise explanation of the particular statutory provisions under which the rule is enacted and how these provisions authorize or require the rule:
This rule was enacted under Subsection 19-2-104(1)(a). Subsection 19-2-104(1)(a) authorizes the Air Quality Board to promulgate rules "regarding the control, abatement, and prevention of air pollution from all sources and the establishment of the maximum quantity of air pollutants that may be emitted by an air pollutant source." Rule R307-361 reduces VOC emissions emitted from architectural coatings by establishing reasonably available control technology (RACT) requirements, as well as clarifying regulatory requirements to the industry.

Content Summary

4. A summary of written comments received during and since the last five-year review of the rule from interested persons supporting or opposing the rule:
There have been no comments in opposition or support of this rule since adoption.

Justification Information

5. A reasoned justification for continuation of the rule, including reasons why the agency disagrees with comments in opposition to the rule, if any:
R307-361 is needed to establish RACT controls in architectural coatings emitting VOCs, which are precursors to the formation of PM2.5. R307-361 is a component of Utah's State Implementation Plan (SIP), and cannot be removed fro the SIP without EPA approval. Therefore, this rule should be continued.

Indexing Information

6. Indexing information - keywords (maximum of four, one term per field, in lower case, except for acronyms (e.g., "GRAMA") or proper nouns (e.g., "Medicaid")):

   air pollution, emission controls, architectural coatings

File Information

7. Attach an RTF document containing the text of this rule change (filename):

   There is a document associated with this rule filing.

To the Agency

Information requested on this form is required by Section 63G-3-305. Incomplete forms will be returned to the agency for completion, possibly delaying the effective date.

Agency Authorization

Agency head or designee, and title:	Bryce Bird Director	Date (mm/dd/yyyy):

ITEM 8

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-065-18

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: September 20, 2018

SUBJECT: Staff Response to Petition for a Rule Change: Utah Petroleum Association Petition for a Rule Change

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On August 15, 2018, the Utah Petroleum Association (UPA) submitted comments on amendments to Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits to the Utah Division of Air Quality (UDAQ). Attached is UPA's Attachment C, Petition for a Rule Change.

R15-2-4 states that a petition shall:

(a) Be clearly designated "petition for a rule change;"
(b) State the petitioner's name;
(c) State the petitioner's interest in the rule, including relevant affiliation, if any;
(d) Include a statement as required by Subsection 63G-3-601(4) regarding the requested rule change;
(e) State the approximate wording of the requested rule change;
(f) Describe the reason for the rule change;
(g) Include an address, an e-mail address when available, and telephone where the petitioner can be reached during regular business hours; and
(h) Be signed by the petitioner.

In the petition, UPA quotes the exact language from the above rule "[s]tate the approximate wording for the requested rule change" and then states eight bullet points outlining measures they believe a Best Available Control Measures analysis of Residential Wood Combustion would identify. These bullet points do not constitute an approximate wording of a requested rule. After thorough review by staff and legal counsel, staff has determined that the Petition for a Rule Change fails to satisfy R15-2-4(e), "State the approximate wording of the requested rule change," therefore failing to meet one of the **required** elements needed to request a rule change.

Recommendation: Staff recommends that the Board deny the petition, instructing staff to notify the petitioner, in writing, of the reasons for denial.

ATTACHMENT C PETITION FOR A RULE CHANGE

August 15, 2018

(a) This constitutes a "petition for a rule change." The following information is provided in accordance with R15-2-4. The *UPA Comments* submitted by UPA on *the PM2.5 Rulemaking* on August 15, 2018 are hereby incorporated by this reference. [1]

(b) State the petitioner's name: Utah Petroleum Association ("UPA") including the following individual member companies: Big West Oil LLC, Chevron Products Company, HollyFrontier Woods Cross Refining LLC, and Tesoro Refining & Marketing Company LLC.

(c) State the petitioner's interest in the rule, including relevant affiliation, if any: UPA is comprised of companies from every segment of the petroleum industry including refiners. Four of UPA's member companies-Big West Oil LLC, Chevron Products Company, HollyFrontier Woods Cross Refining LLC, and Tesoro Refining & Marketing Company LLC -operate refineries that are identified in the Utah's PM2.5 SIP rulemaking as major stationary sources subject to the emission limits being proposed in this rulemaking. UPA and each of these companies are interested in seeing Utah implement appropriate control measures, including for area sources and residential wood combustion ("RWC"), that will contribute to the attainment and maintenance of the PM2.5 National Ambient Air Quality Standards in the Salt Lake City Nonattainment Area (SLC NAA). Absent effective control measures, UPA and its member companies will be subject to ever more stringent control measures.[2]

(d) Include a statement as required by Subsection 63G-3-601(4) regarding the requested rule change: The proposed action is within the jurisdiction and appropriate to the powers of the Utah Division of Air Quality and the Utah Air Quality Board ("Board"). The Board is authorized to "establish emission control requirements by rule that in its judgment may be necessary to prevent, abate, or control air pollution that may be statewide or may vary from area to area, taking into account varying local conditions."[3] In fact, the Board has previously enacted R307-302, Solid Fuel Burning Devices in Box Elder, Cache, Davis, Salt Lake, Tooele, Utah, and Weber Counties, which regulates RWC.

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[1] SIP Subsection IX. Part H: Emission Limits and Operating Practices and R307-110-17, Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits. *See* 2018-13 Utah Bull. pp. 34-36 (July 1, 2018); *see also* Utah Air Quality Board, Final Agenda, Items VIII and IX (June 6, 2018) (collectively referred to as *"the PM2.5 Rulemaking').*

UPA has submitted comments on the proposed *PM2.5 Rulemaking* (referred to herein as *UPA Comments).* The second comment, "THE PROPOSED SIP CONTAINS INADEQUATE CONTROL MEASURES FOR WOOD BURNING EMISSIONS," addresses in detail the legal and technical reasons for Utah adopting additional control measures to control emissions associated with residential wood combustion.

[2] *See, e.g.,* 40 CFR § 51.1010(b) (requiring "most stringent measures" for Serious nonattainment areas that cannot make an attainment demonstration by the attainment deadline); *id.* § 51.10IO(c) (requiring a five percent reduction in direct PM2.5 or its precursors for Serious nonattainment areas that fail to demonstrate attainment by the attainment deadline).

[3] Utah Code Ann. § 19-2-109(2)(a).

(e) State the approximate wording of the requested rule change: In the UPA Comments, UPA identified a number of state regulations governing RWC that UDAQ has yet to consider as well as measures from the one state regulation (i.e., the San Joaquin Valley Air Pollution Control District Rule 4901) that UDAQ reviewed but did not implement. UPA believes that a Best Available Control Measures ("BACM") analysis of RWC would result in the adoption of the following measures as BACM for the SLC NAA:[4]

- Provisions imposing mandatory change-out of existing solid fuel burning devices ("SFBD") (Puget Sound Clean Air Agency ("PSCAA")).
- Requirements to change-out existing SFBD during real estate transactions or to render existing SFBD inoperable during real estate transactions (Fairbanks, City of Portola).
- Requirements limiting the installation of SFBD in new residential developments (SJVAPCD).
- Adoptions of an incentive program for SFBD change-outs (City of Portola).
- Adoption of more stringent requirements on the moisture content of fuel burned and public education regarding moisture content in fuel (SJVAPCD, PSCAA, City of Portola).
- Requirements for retailers selling SFBD and fuel for SFBD (Fairbanks, City of Portola).
- Review of emission standards imposed by other air agencies (Fairbanks, PSCAA).
- Conduct ongoing public education campaign(s) to inform the public on the impacts of RWC and proper use of SBFDs (SJVAPCD, Fairbanks).

(f) Describe the reason for the rule change: RWC contributes significantly to the SLC NAA's PM2.5 concentrations. Current Utah rules and proposed rules do not address the legal requirements for controlling RWC emissions. Absent appropriate controls, UPA and its member companies will be subject to increasingly stringent controls that will prove costly and ineffective. The reason for the requested rule change is set forth more fully in *UPA Comments.*

(g) Include an address, an e-mail address when available, and telephone where the petitioner can be reached during regular business hours:

Utah Petroleum Association
10714 S. Jordan Gateway, Suite 160
South Jordan, Utah 84095
801-619-6680

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[4] In the subsequent list, UPA identifies the state/local agency that adopted the condition that UPA believes constitutes BACM for the SLC NAA. Please refer to UPA's Comment, which provides additional details on the measures adopted by these state and local air quality agencies as well as precise legal citations for those regulations. UPA's survey of state regulations governing RWC was not exhaustive and, as such, UPA encourages UDAQ to conduct a comprehensive survey of other state regulation as EPA directed in the PM2.5 Implementation Rule. 40 CFR § 51.1010(a)(2)(i); 81 Fed. Reg. 58010, 58084/2 (August 24, 2016).

jking@utahpetroleum.org

(h) This petition is respectfully submitted by the Utah Petroleum Association this 15th day of August, 2018.

Utah Petroleum Association

By: ______________________
Jennette King

Its: ______________________
Administrative Assitant

4824-4655-2688v4

ITEM 9

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-806-18

M E M O R A N D U M

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: Sept 10, 2018

SUBJECT: Air Toxics, Lead-Based Paint, and Asbestos (ATLAS) Section Compliance Activities – August 2018

Asbestos Demolition/Renovation NESHAP Inspections	16
Asbestos AHERA Inspections	15
Asbestos State Rules Only Inspections	1
Asbestos Notification Forms Accepted	153
Asbestos Telephone Calls	440
Asbestos Individuals Certifications Approved/Disapproved	91/0
Asbestos Company Certifications/Re-Certifications	2/1
Asbestos Alternate Work Practices Approved/Disapproved	8/0
Lead-Based Paint (LBP) Inspections	15
LBP Notification Forms Approved	1
LBP Telephone Calls	56
LBP Letters Prepared and Mailed	11
LBP Courses Reviewed/Approved	0/0
LBP Course Audits	1
LBP Individual Certifications Approved/Disapproved	8/0
LBP Firm Certifications	10

Notices of Violation Sent	0
Compliance Advisories Sent	11
Warning Letters Sent	7
Settlement Agreements Finalized	5
Penalties Agreed to:	
Sevier County School District	$ 162.50
Beaver County School District	$ 227.50
J-Corp Development Inc., & Rise Development	$ 3,900.00
Any Hour Electric, Plumbing, Heating, and Air	$ 1,125.00
Vincent Construction	$ 4,687.50

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-2085-18

M E M O R A N D U M

TO: Air Quality Board

FROM: Bryce C. Bird, Executive Secretary

DATE: September 12, 2018

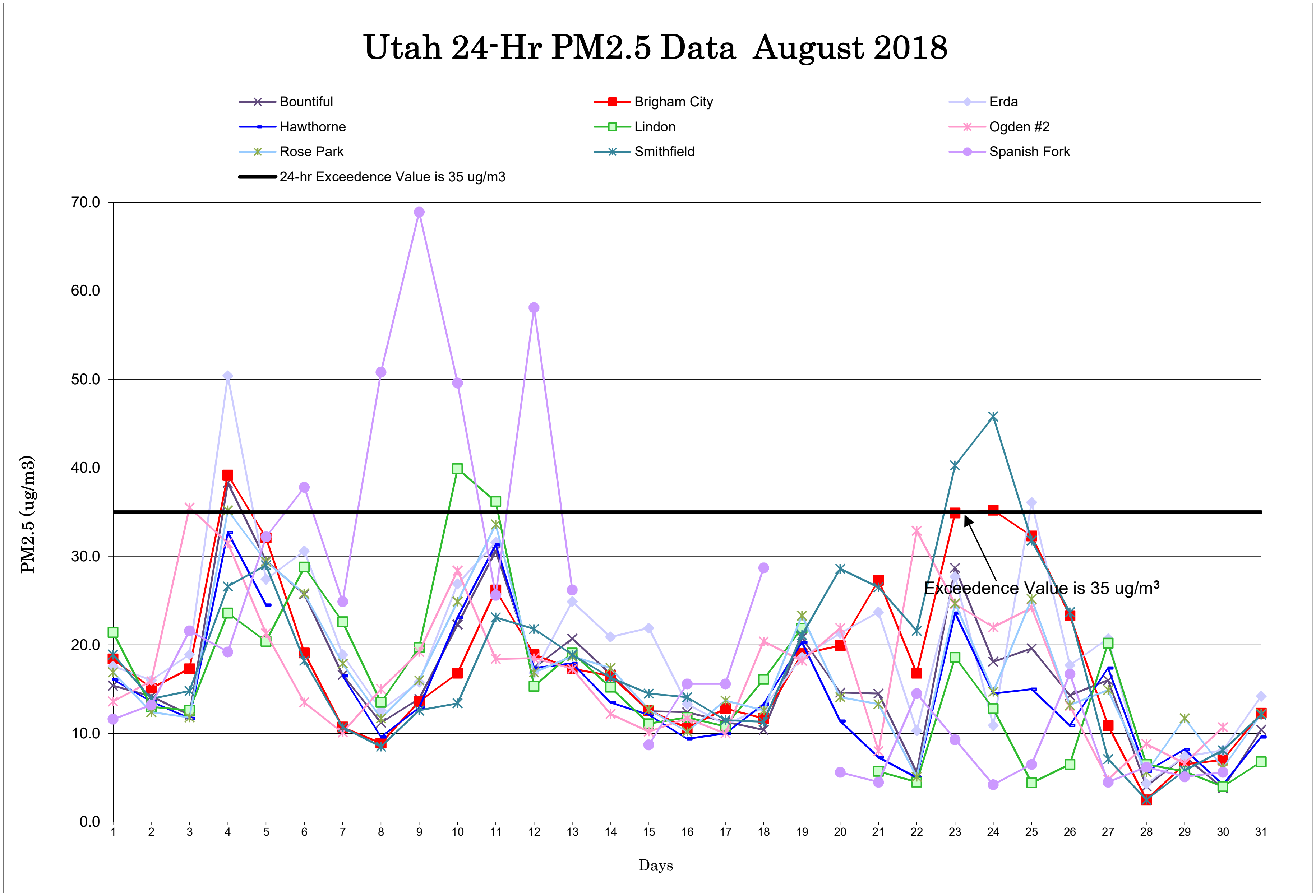
SUBJECT: Compliance Activities – August 2018

Annual Inspections Conducted:	
Major	9
Synthetic Minor	8
Minor	48
On-Site Stack Test Audits Conducted:	5
Stack Test Report Reviews:	18
On-Site CEM Audits Conducted:	0
Emission Reports Reviewed:	16
Temporary Relocation Requests Reviewed & Approved:	9
Fugitive Dust Control Plans Reviewed & Accepted:	215
Soil Remediation Report Reviews:	1
[1]Miscellaneous Inspections Conducted:	30
Complaints Received:	17
Breakdown Reports Received:	0

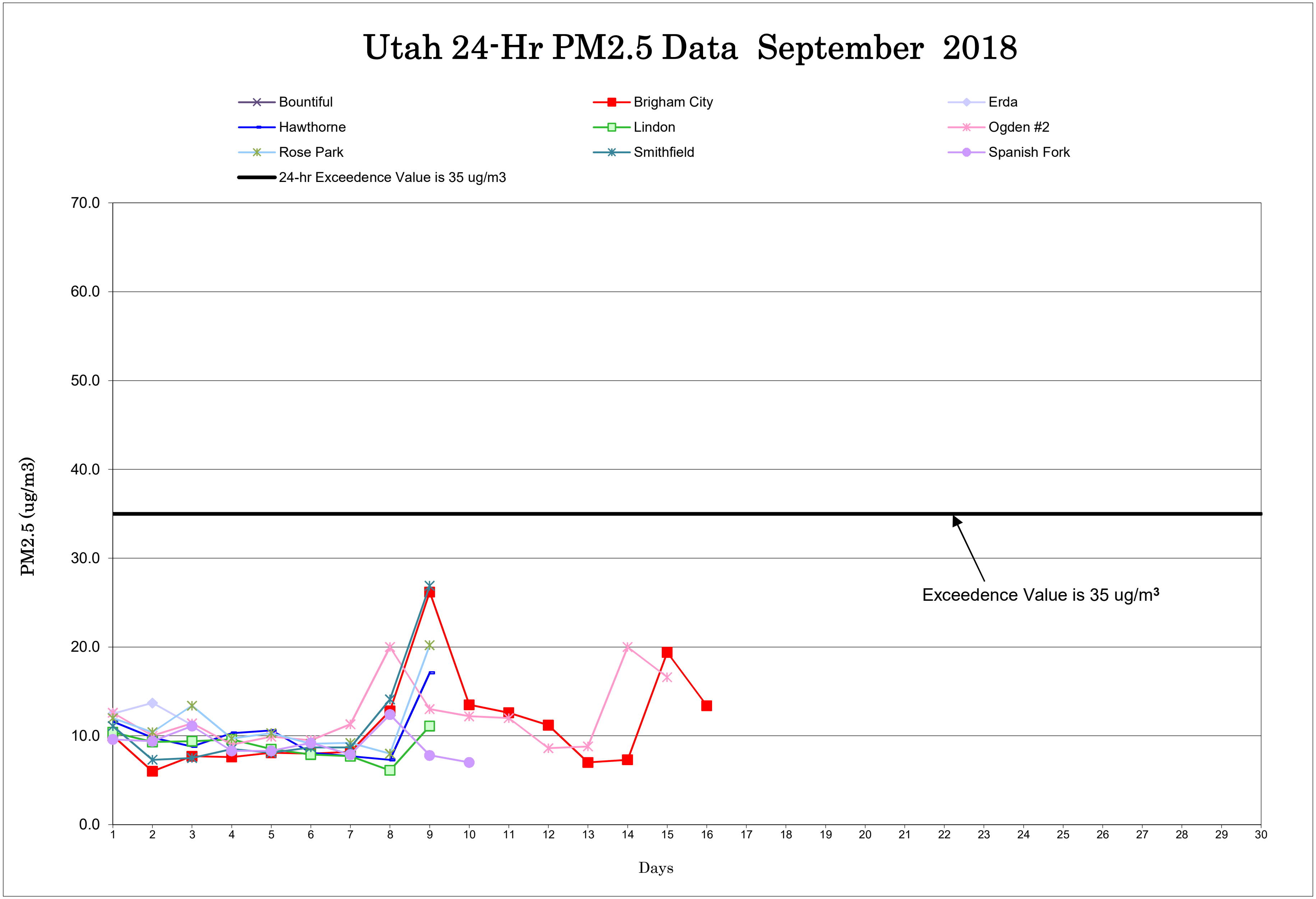
Compliance Actions Resulting From a Breakdown	0
Warning Letters Issued:	5
Notices of Violation Issued:	0
Compliance Advisories Issued:	7
No Further Action Letters Issued	0
Settlement Agreements Reached:	2
Quality Crushing	$4,119.00
Newfield Production	$359.00

[1]Miscellaneous inspections include, e.g., surveillance, level I inspections, VOC inspections, complaints, on-site training, dust patrol, smoke patrol, open burning, etc.

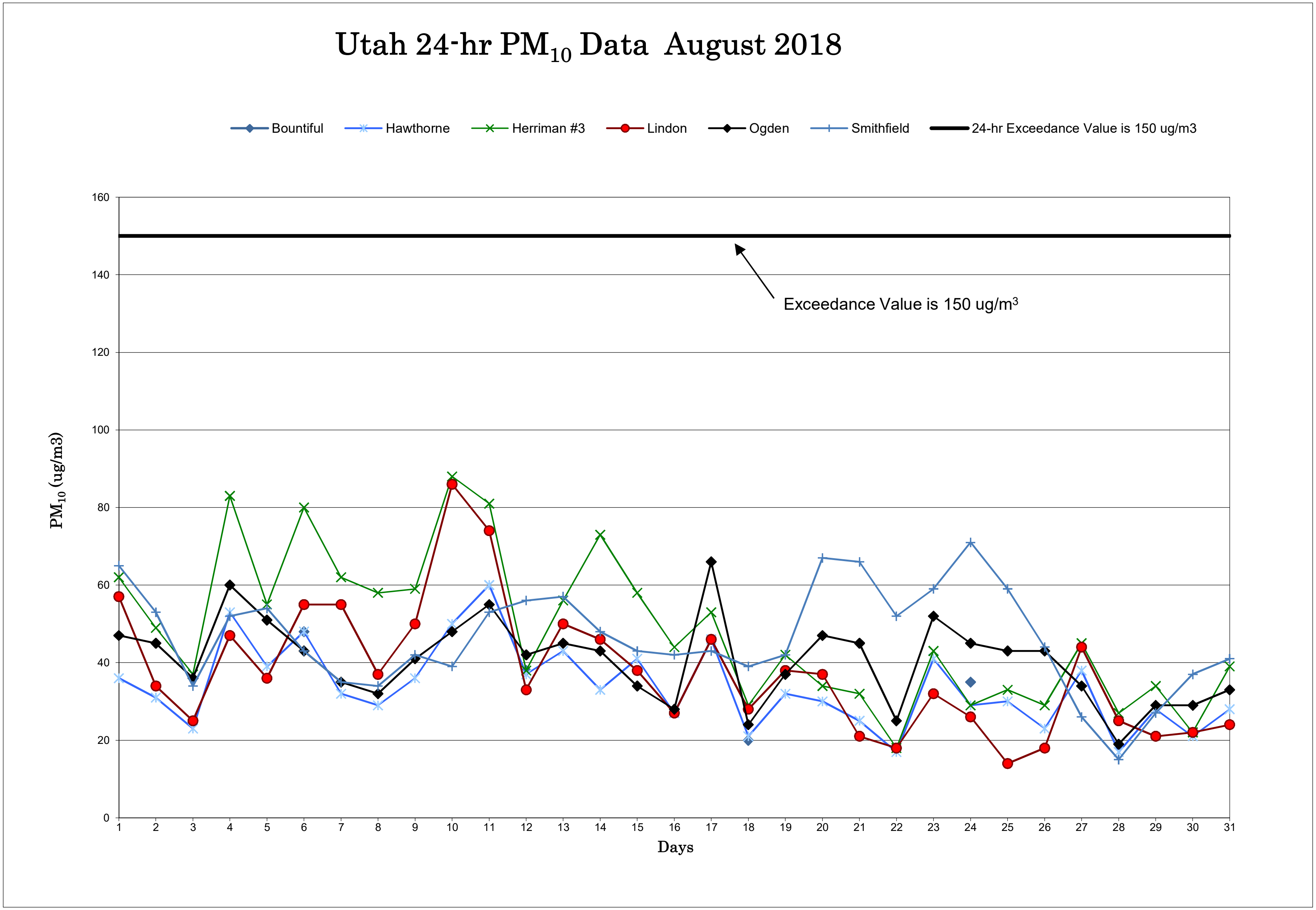
Air Monitoring



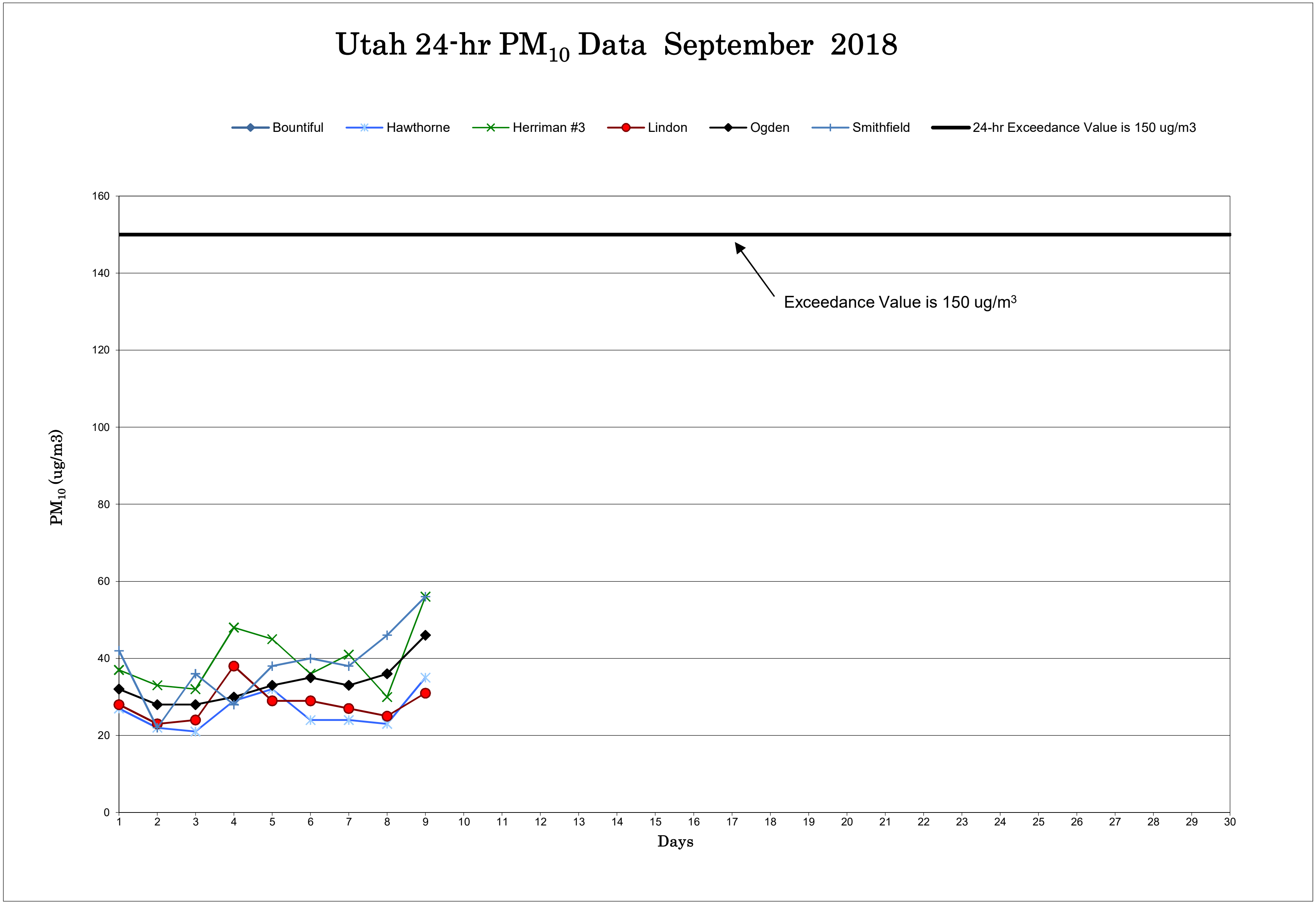
Utah Division of Air Quality



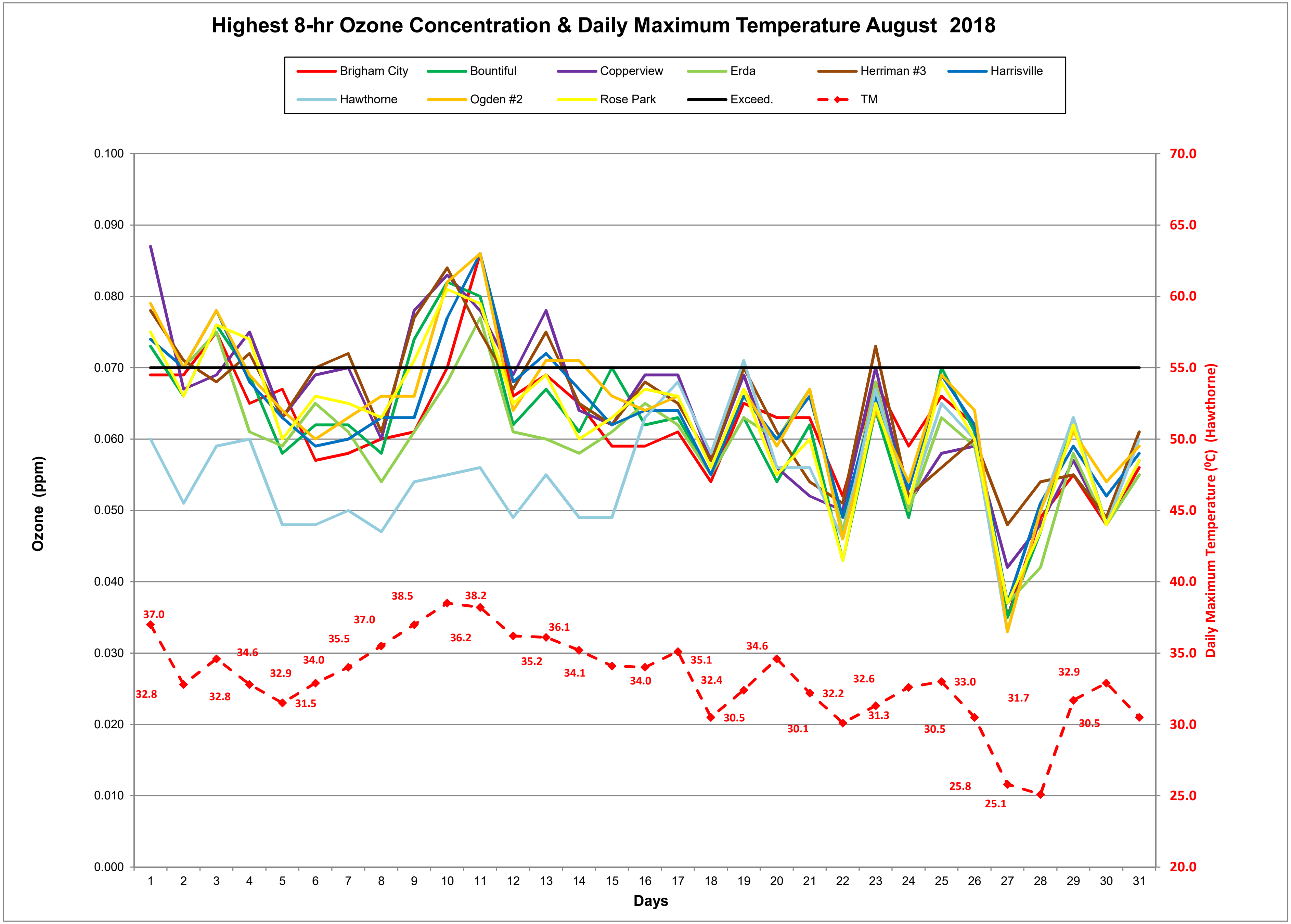
Utah 24-Hr PM2.5 Data September 2018
Bountiful
Brigham City
Erda
Hawthorne
Lindon
Ogden #2
Rose Park
Smithfield
Spanish Fork
24-hr Exceedence Value is 35 ug/m3
PM2.5 (ug/m3)
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
Exceedence Value is 35 ug/m³
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Days

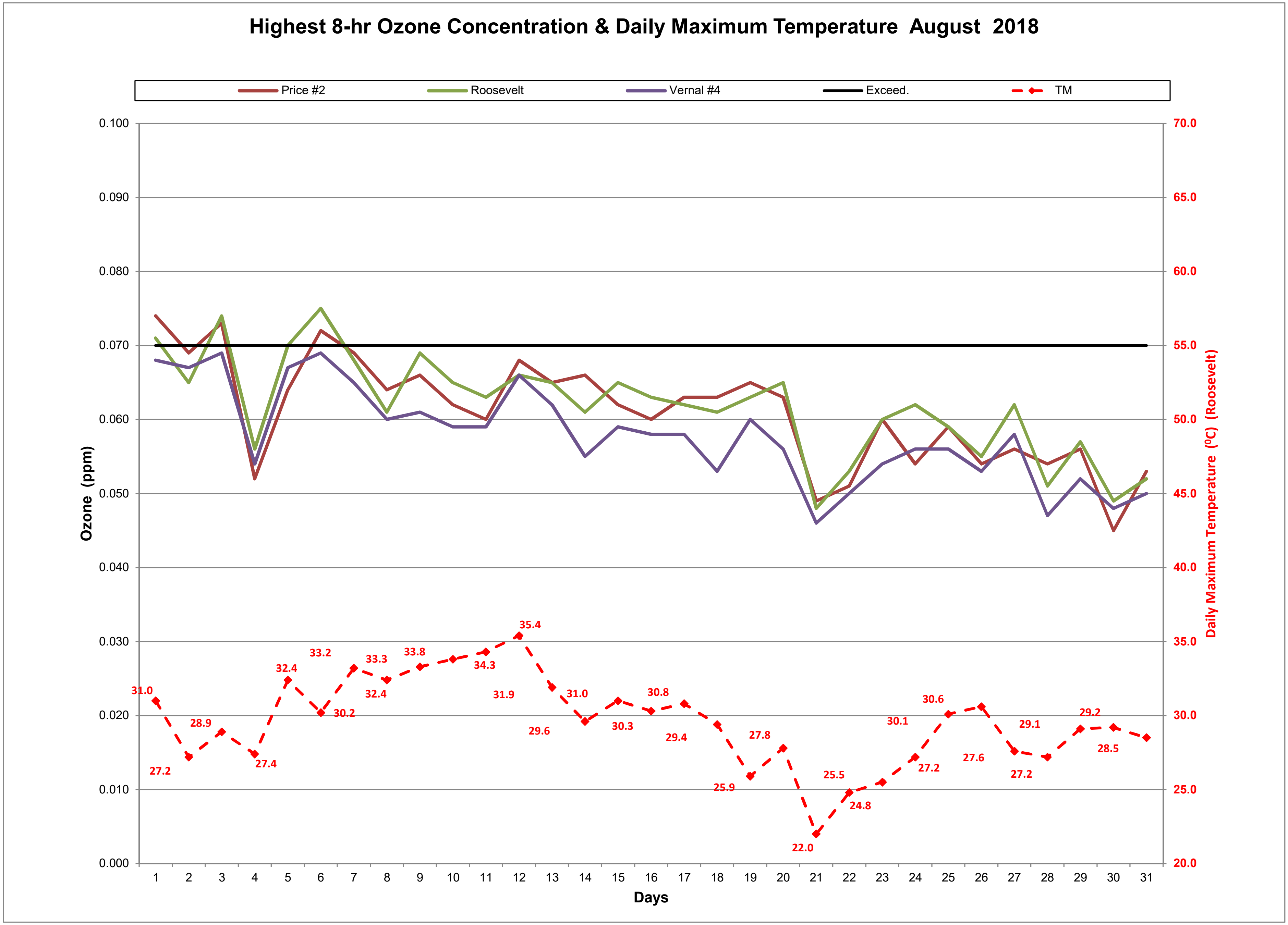


Utah Division of Air Quality

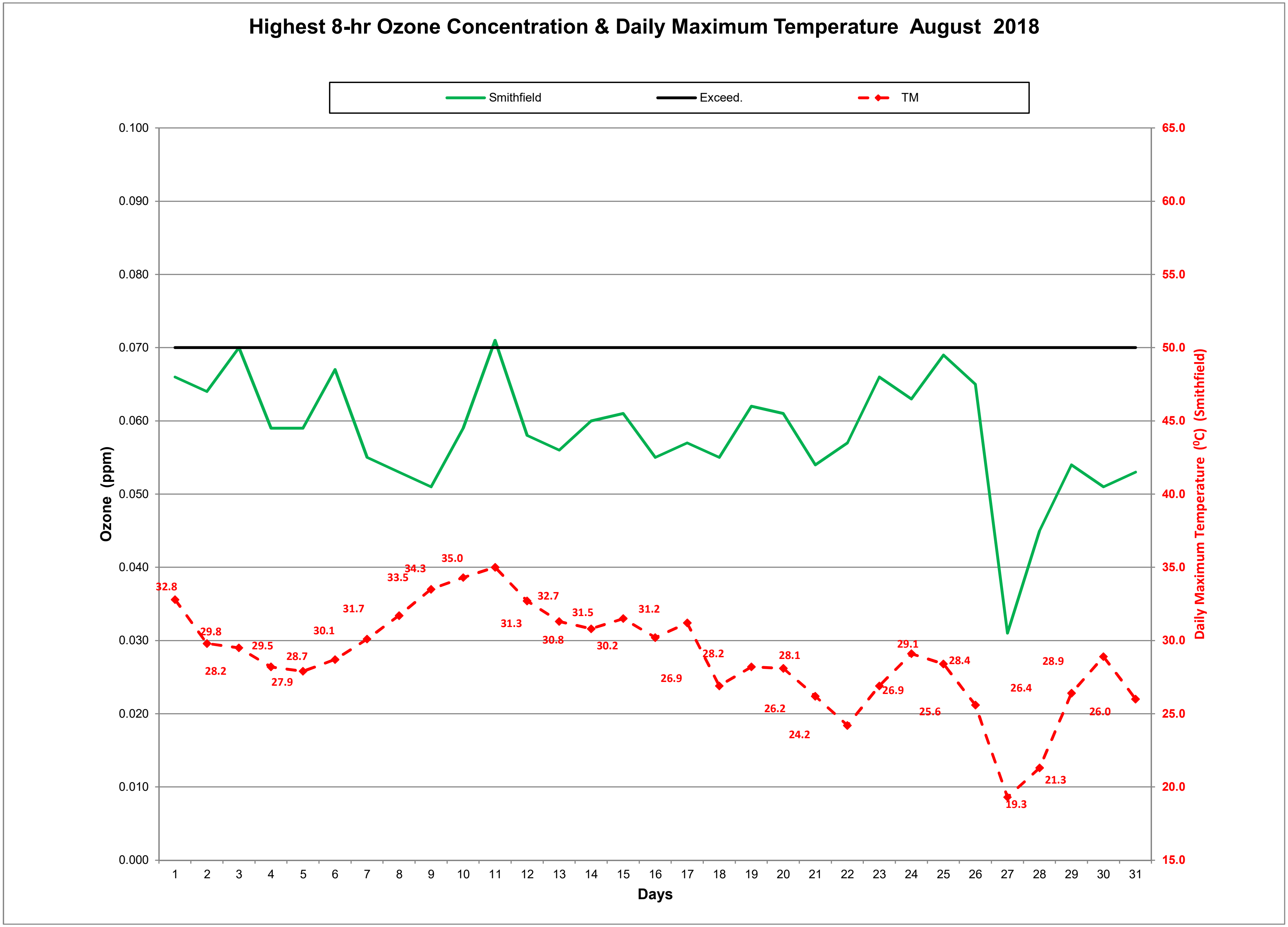


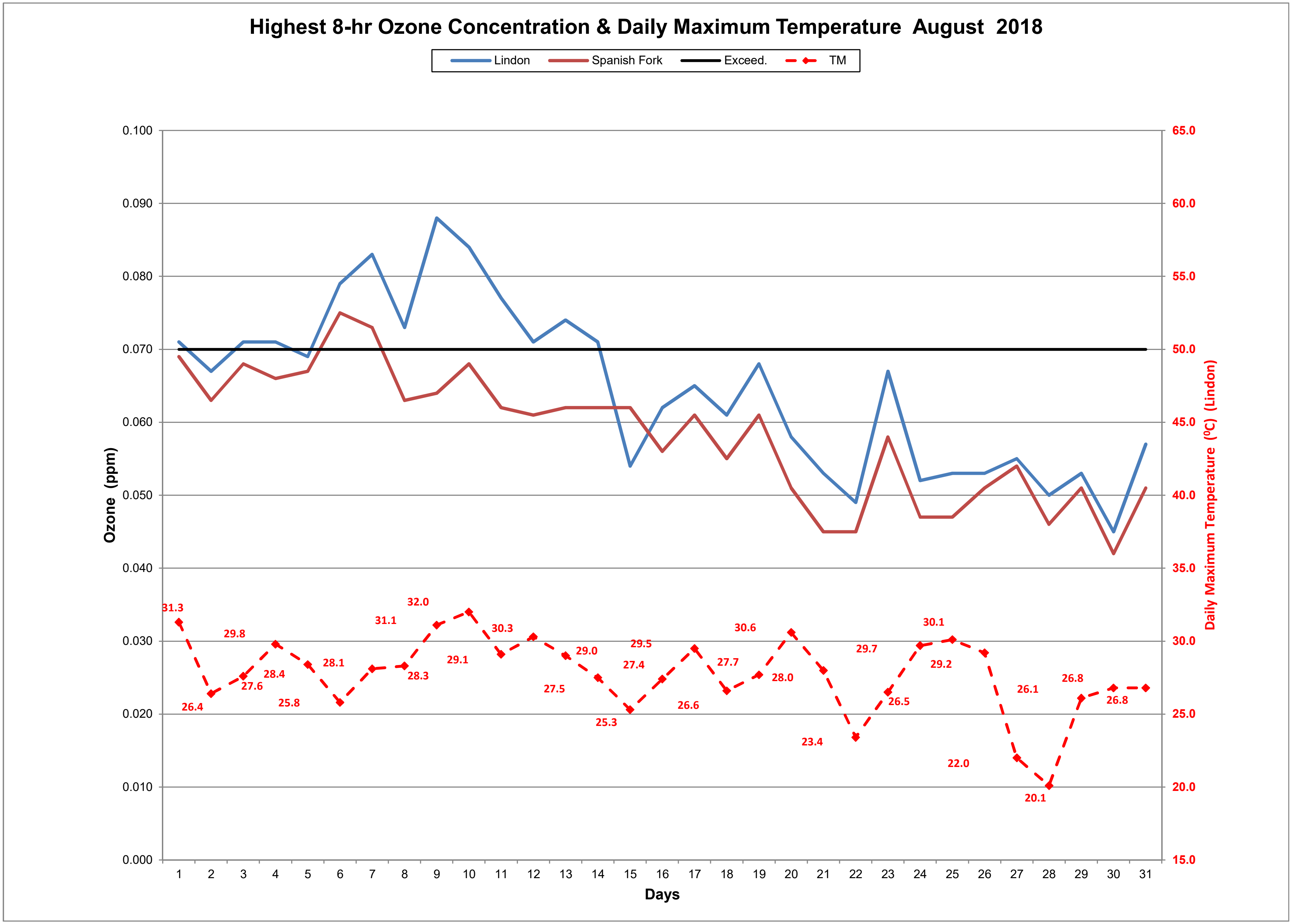
Utah Division of Air Quality


Highest 8-hr Ozone Concentration & Daily Maximum Temperature August 2018
Brigham City
Bountiful
Copperview
Erda
Herriman #3
Harrisville
Hawthorne
Ogden #2
Rose Park
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (⁰C) (Hawthorne)
Days

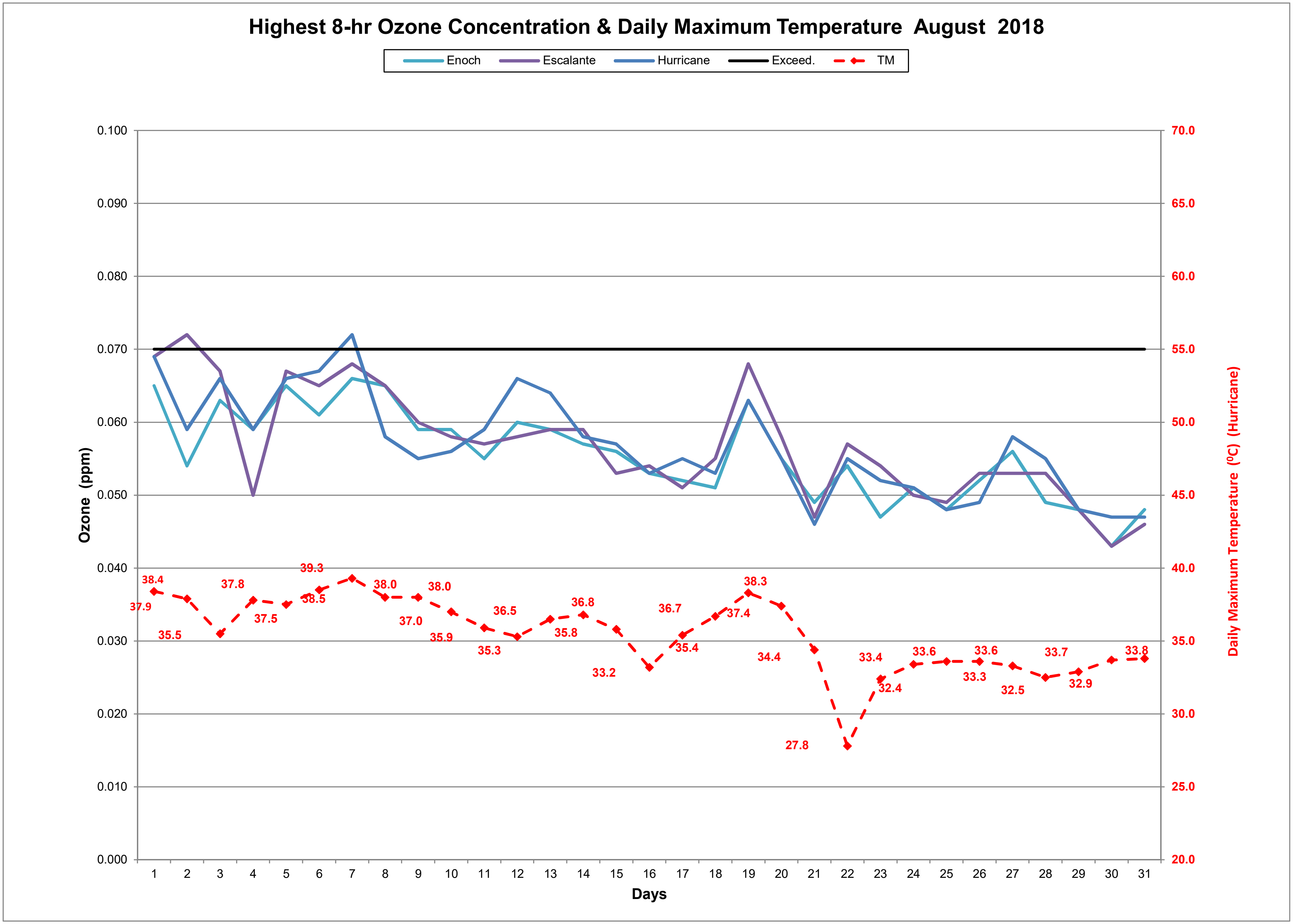


Highest 8-hr Ozone Concentration & Daily Maximum Temperature August 2018
Price #2
Roosevelt
Vernal #4
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (ºC) (Roosevelt)
Days
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
70.0
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
1 2 3 4 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 31
31.0
27.2
28.9
27.4
32.4
33.2
30.2
33.3
32.4
33.8
34.3
31.9
35.4
29.6
31.0
30.3
30.8
29.4
25.9
27.8
22.0
25.5
24.8
30.1
27.2
30.6
27.6
29.1
27.2
29.2
28.5

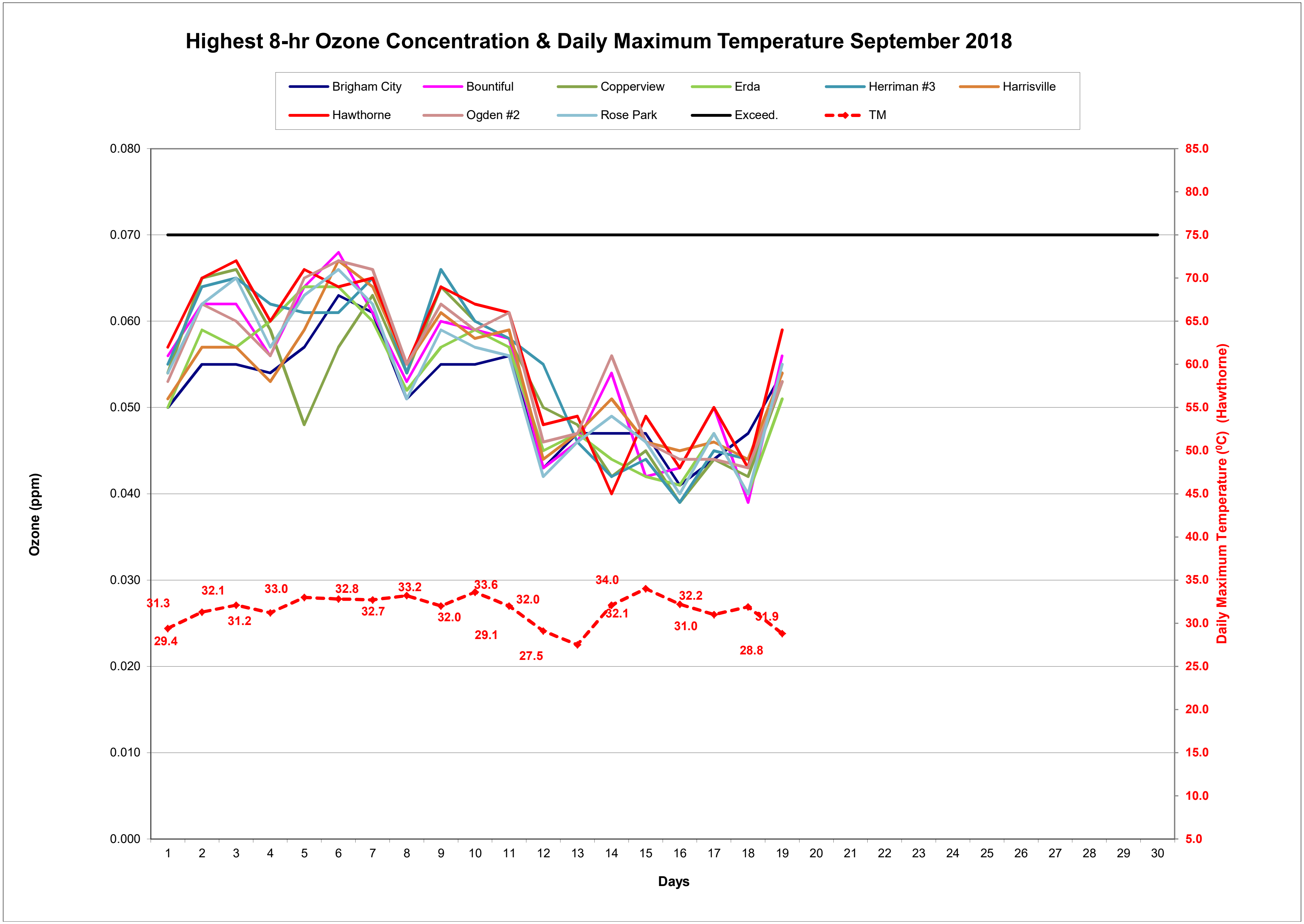

Highest 8-hr Ozone Concentration & Daily Maximum Temperature August 2018
Smithfield
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (⁰C) (Smithfield)
Days
32.8
29.8
28.2
29.5
27.9
28.7
30.1
31.7
33.5
34.3
35.0
31.3
32.7
30.8
31.5
30.2
31.2
26.9
28.2
26.2
28.1
24.2
26.9
29.1
25.6
28.4
26.4
19.3
21.3
28.9
26.0

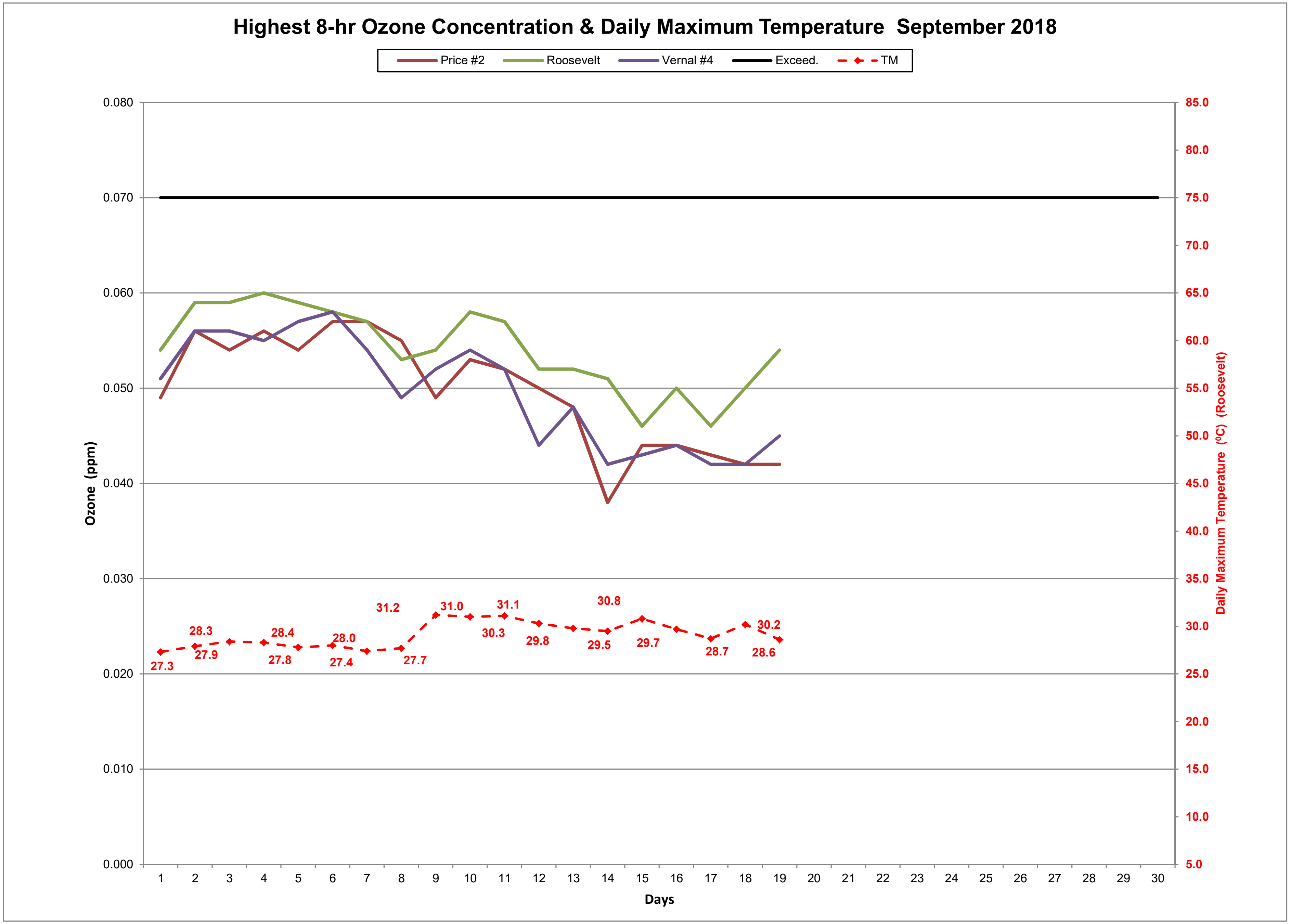


Highest 8-hr Ozone Concentration & Daily Maximum Temperature August 2018
Lindon
Spanish Fork
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (ºC) (Lindon)
Days
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
31.3
26.4
27.6
29.8
28.4
25.8
28.1
31.1
28.3
32.0
29.1
30.3
27.5
29.0
25.3
29.5
27.4
26.6
27.7
30.6
28.0
23.4
29.7
26.5
30.1
29.2
22.0
26.1
20.1
26.8
26.8

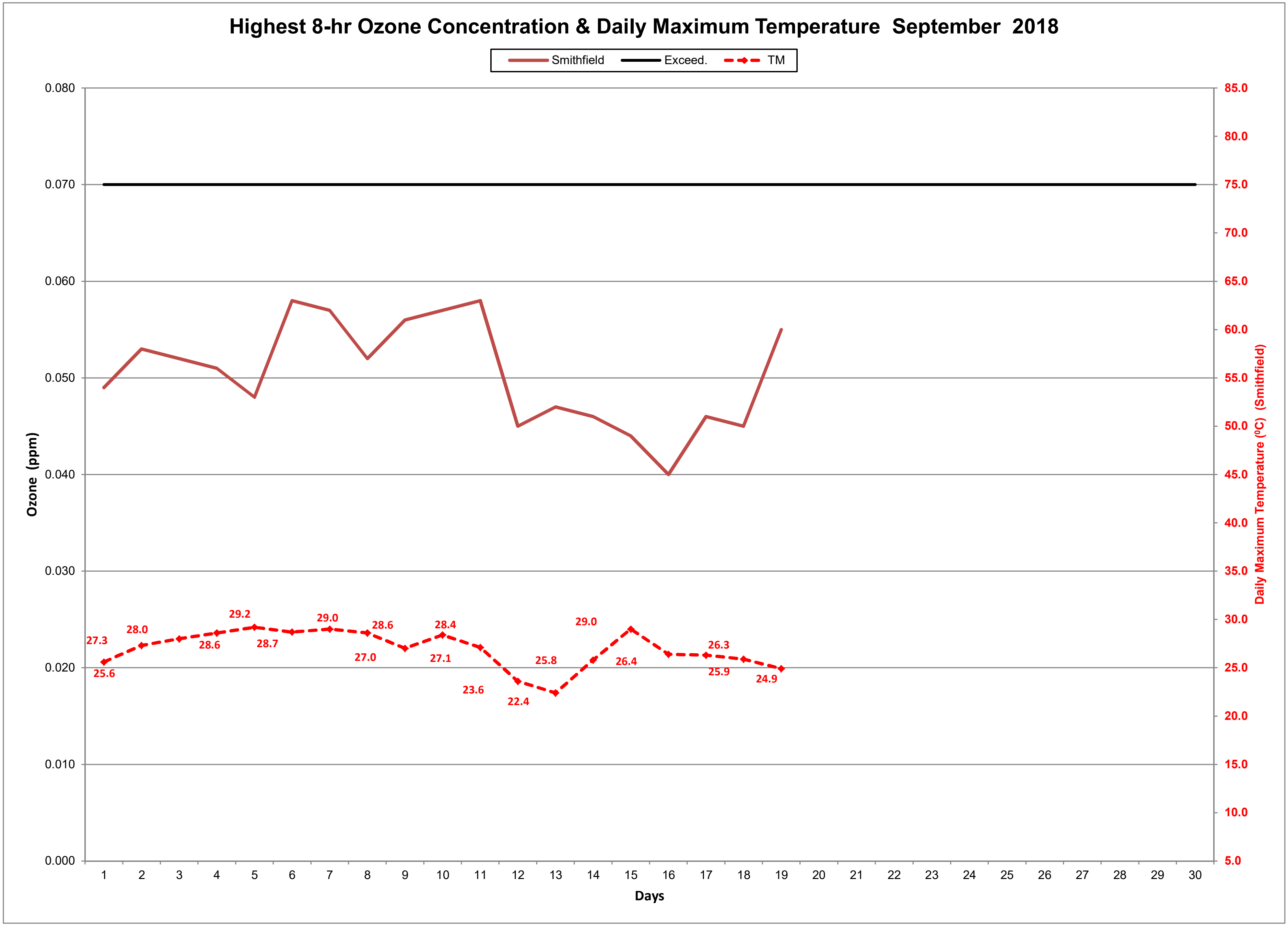


Highest 8-hr Ozone Concentration & Daily Maximum Temperature August 2018
Enoch
Escalante
Hurricane
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (ºC) (Hurricane)
Days
0.100
0.090
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
70.0
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
1 2 3 4 5 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 31
38.4
37.9
35.5
37.8
37.5
39.3
38.5
38.0
37.0
38.0
35.9
35.3
36.5
35.8
36.8
33.2
36.7
35.4
37.4
38.3
34.4
27.8
33.4
32.4
33.6
33.3
33.6
32.5
33.7
32.9
33.8

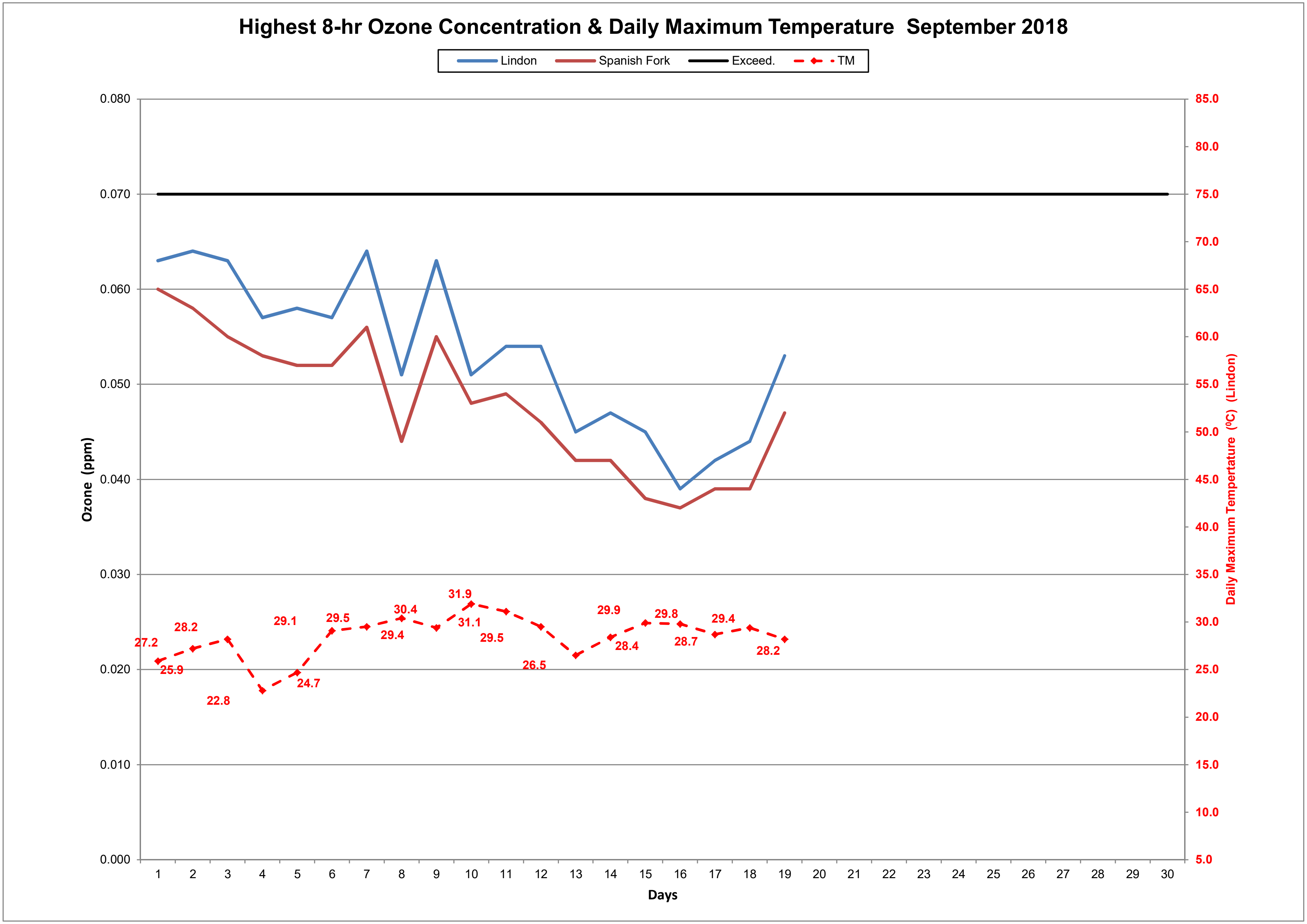

Highest 8-hr Ozone Concentration & Daily Maximum Temperature September 2018
Brigham City
Bountiful
Copperview
Erda
Herriman #3
Harrisville
Hawthorne
Ogden #2
Rose Park
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (⁰C) (Hawthorne)
Days
31.3
29.4
32.1
31.2
33.0
32.8
32.7
33.2
32.0
33.6
29.1
32.0
27.5
34.0
32.1
32.2
31.0
31.9
28.8



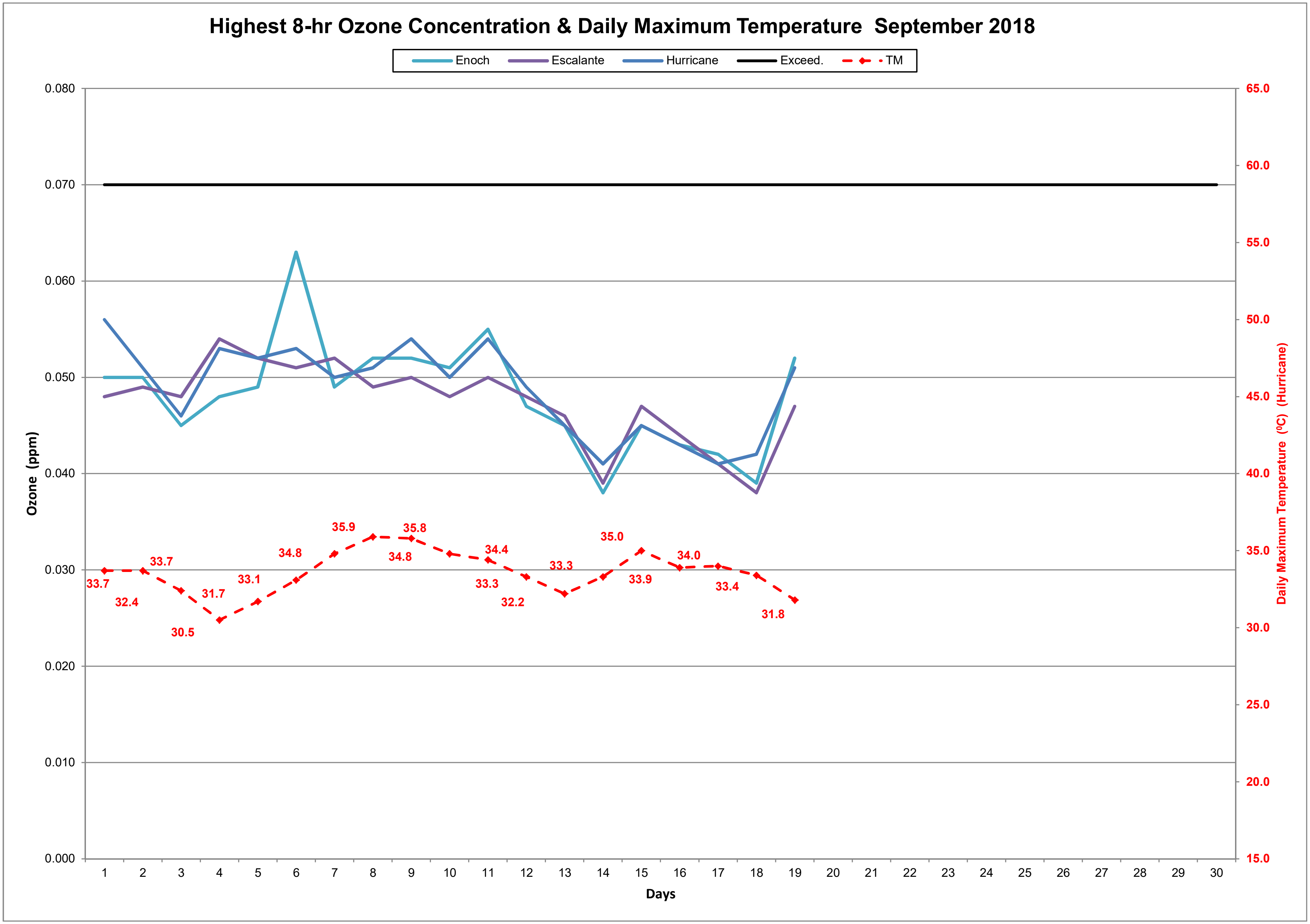
Highest 8-hr Ozone Concentration & Daily Maximum Temperature September 2018
Price #2
Roosevelt
Vernal #4
Exceed.
TM
Ozone (ppm)
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
Daily Maximum Temperature (⁰C) (Roosevelt)
85.0
80.0
75.0
70.0
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
Days
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
27.3
28.3
27.9
28.4
27.8
28.0
27.4
31.2
27.7
31.0
30.3
31.1
29.8
30.8
29.5
29.7
28.7
30.2
28.6



Highest 8-hr Ozone Concentration & Daily Maximum Temperature September 2018
Smithfield
Exceed.
TM
Ozone (ppm)
Daily Maximum Temperature (ºC) (Smithfield)
Days
0.000
0.010
0.020
0.030
0.040
0.050
0.060
0.070
0.080
5.0
10.0
15.0
20.0
25.0
30.0
35.0
40.0
45.0
50.0
55.0
60.0
65.0
70.0
75.0
80.0
85.0
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
25.6
27.3
28.0
28.6
29.2
28.7
29.0
28.6
27.0
28.4
27.1
23.6
22.4
25.8
29.0
26.4
26.3
25.9
24.9



Highest 8-hr Ozone Concentration & Daily Maximum Temperature September 2018
Lindon
Spanish Fork
Exceed.
TM
Ozone (ppm)
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
Daily Maximum Tempertature (ºC) (Lindon)
85.0
80.0
75.0
70.0
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
Days
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
27.2
25.9
28.2
22.8
29.1
24.7
29.5
29.4
30.4
31.9
31.1
29.5
26.5
29.9
28.4
29.8
28.7
29.4
28.2



Highest 8-hr Ozone Concentration & Daily Maximum Temperature September 2018
Enoch
Escalante
Hurricane
Exceed.
TM
Ozone (ppm)
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
Daily Maximum Temperature (°C) (Hurricane)
65.0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
33.7
32.4
33.7
30.5
31.7
33.1
34.8
35.9
34.8
35.8
34.4
33.3
32.2
33.3
35.0
33.9
34.0
33.4
31.8
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
Days

Other Items to be Brought Before the Board

UTAH DEPARTMENT *of* ENVIRONMENTAL QUALITY

AIR QUALITY

UDAQ: Science for Solutions Grant

Step 1

UDAQ Annual Goals and Priorities List

A Panel within UDAQ develops a list of semi-broad goal and priority topics (e.g. improving ammonia inventory). This list will be re-evaluated each year, and will changed based on the specific research needs at that particular time.

Step 2

AiR^2: Gathering of Researchers - Input to Refine Annual Goals and Priorities List

UDAQ will host a roundtable conference with researchers to determine if any additional topics should be added/removed to the goals and priorities list. UDAQ still has the ultimate say as to what gets included on the list. This event, AiR2, will be hosted by UDAQ each October.

Step 3

Request for Proposals (RFP)

The formal RFP will be based on the Annual Goals and Priorities List. The RFP will be posted on DAQ's webpage here: URL

Step 4

Review/Scoring and Selection of Project Proposals

A UDAQ panel will use the grant scoring criteria developed prior to Step 2 to review, score, and select project proposals to fund. If needed, consultation with individual subject matter experts (SME) will occur.

Step 5

Funding Process and Allocation of Funds

Each project that UDAQ decides to fund will need to go through the necessary state contracting process. July 1st is the earliest funds will be available.

UDAQ Pre-Steps

- Develop grant scoring criteria.

UTAH DEPARTMENT *of* ENVIRONMENTAL QUALITY

AIR QUALITY

Science for Solutions Research Grant

Step 4b

Project Proposal Modifications and Budget Adjustments as Needed

The UDAQ panel, especially after consultation with SME, may require slight project proposal modifications. Budget modifications may also be needed to ensure adequate funding for all selected projects.

Recipient Requirements

1. Quarterly Reports
2. Final Report - 90 Days after project completion.
3. Data Sharing
4. Presentation at Science for Solutions Conference.

UTAH DEPARTMENT of ENVIRONMENTAL QUALITY
AIR QUALITY

Important Dates

- **Oct 4th 2018**
  - UDAQ research goals and priorities discussion to gather input from research community (AiR² meeting)
- **Oct 15th 2018**
  - List of research goals and priorities finalized
- **Nov 1st 2018**
  - Announcement of formal UDAQ Request for Proposal (RFP)
- **Jan 4th 2019**
  - All research proposals due to UDAQ
- **Jan. 17th 2019**
  - Proposal review process by internal UDAQ committee begins
- **March 15th 2019**
  - Award recipients selected
- **April 1st 2019**
  - Requested modifications and budget adjustments due to UDAQ
  - UDAQ contracting process begins
- **July 1st 2019**
  - Earliest that funds are disbursed to award recipients

2018